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EPA Office of Compliance Sector Notebook Project

Profile of the Oil and Gas Extraction Industry

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Office of Compliance
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
401 M St., SW
Washington, DC 20460

This report is one in a series of volumes published by the U.S. Environmental Protection Agency (EPA) to provide information of general interest regarding environmental issues associated with specific industrial sectors. The documents were developed under contract by Abt Associates (Cambridge, MA), Science Applications International Corporation (McLean, VA), and Booz-Allen & Hamilton, Inc. (McLean, VA). A listing of available Sector Notebooks is included on the following page.

Obtaining copies:

Electronic versions of all sector notebooks are available via Internet on the Enviroene World Wide Web at *www.epa.gov/oeca/sector*. Enviroene is a free, public, environmental exchange system operated by EPA's Office of Enforcement and Compliance Assurance and Office of Research and Development. The Network allows regulators, the regulated community, technical experts, and the general public to share information regarding: pollution prevention and innovative technologies; environmental enforcement and compliance assistance; laws, executive orders, regulations, and policies; points of contact for services and equipment; and other related topics. The Network welcomes receipt of environmental messages, information, and data from any public or private person or organization. Direct technical questions to the “Feedback” button on the bottom of the web page.

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The Sector Notebooks were developed by the EPA’s Office of Compliance. Direct general questions about the Sector Notebook Project to:

Seth Heminway, Coordinator, Sector Notebook Project
US EPA Office of Compliance
401 M St., SW (2223-A)
Washington, DC 20460
(202) 564-7017

For further information, and for answers to questions pertaining to these documents, please refer to the contact names listed on the following page.

SECTOR NOTEBOOK CONTACTS

Questions and comments regarding the individual documents should be directed to the specialists listed below. **See the Notebook web page at: *www.epa.gov/oeca/sector* for the most recent titles and staff contacts.**

EPA Publication Number	Industry	Contact	Phone (202)
EPA/310-R-95-001.	Profile of the Dry Cleaning Industry	Joyce Chandler	564-7073
EPA/310-R-99-003.	Profile of the Agricultural Chemical, Pesticide and Fertilizer Industry	Michelle Yaras	564-4153
EPA/310-R-99-004.	Profile of the Agricultural Crop Production Industry	Ginah Mortensen	913-551-5211
EPA/310-R-99-005.	Profile of the Agricultural Livestock Production Industry	Ginah Mortensen	913-551-5211
EPA/310-R-95-002.	Profile of the Electronics and Computer Industry*	Steve Hoover	564-7007
EPA/310-R-95-003.	Profile of the Wood Furniture and Fixtures Industry	Bob Marshall	564-7021
EPA/310-R-95-004.	Profile of the Inorganic Chemical Industry*	Walter DeRieux	564-7067
EPA/310-R-95-005.	Profile of the Iron and Steel Industry	Maria Malave	564-7027
EPA/310-R-95-006.	Profile of the Lumber and Wood Products Industry	Seth Heminway	564-7017
EPA/310-R-95-007.	Profile of the Fabricated Metal Products Industry*	Scott Throwe	564-7013
EPA/310-R-95-008.	Profile of the Metal Mining Industry	Maria Malave	564-5027
EPA/310-R-95-009.	Profile of the Motor Vehicle Assembly Industry	Anthony Raia	564-6045
EPA/310-R-95-010.	Profile of the Nonferrous Metals Industry	Debbie Thomas	564-5041
EPA/310-R-95-011.	Profile of the Non-Fuel, Non-Metal Mining Industry	Rob Lischinsky	564-2628
EPA/310-R-95-012.	Profile of the Organic Chemical Industry *	Walter DeRieux	564-7067
EPA/310-R-99-006.	Profile of the Oil and Gas Extraction Industry	Dan Chadwick	564-7054
EPA/310-R-95-013.	Profile of the Petroleum Refining Industry	Tom Ripp	564-7003
EPA/310-R-95-014.	Profile of the Printing Industry	Ginger Gotliffe	564-7072
EPA/310-R-95-015.	Profile of the Pulp and Paper Industry	Seth Heminway	564-7017
EPA/310-R-95-016.	Profile of the Rubber and Plastic Industry	Robert Tolpa	564-2337
EPA/310-R-95-017.	Profile of the Stone, Clay, Glass, and Concrete Ind.	Scott Throwe	564-7013
EPA/310-R-95-018.	Profile of the Transportation Equipment Cleaning Ind.	Virginia Lathrop	564-7057
EPA/310-R-97-001.	Profile of the Air Transportation Industry	Virginia Lathrop	564-7057
EPA/310-R-97-002.	Profile of the Ground Transportation Industry	Virginia Lathrop	564-7057
EPA/310-R-97-003.	Profile of the Water Transportation Industry	Virginia Lathrop	564-7057
EPA/310-R-97-004.	Profile of the Metal Casting Industry	Steve Hoover	564-7007
EPA/310-R-97-005.	Profile of the Pharmaceuticals Industry	Emily Chow	564-7071
EPA/310-R-97-006.	Profile of the Plastic Resin and Man-made Fiber Ind.	Sally Sasnett	564-7074
EPA/310-R-97-007.	Profile of the Fossil Fuel Electric Power Generation Industry	Rafael Sanchez	564-7028
EPA/310-R-97-008.	Profile of the Shipbuilding and Repair Industry	Anthony Raia	564-6045
EPA/310-R-97-009.	Profile of the Textile Industry	Belinda Breidenbach	564-7022
EPA/310-R-98-001.	Profile of the Aerospace Industry	Anthony Raia	564-6045
EPA/310-R-97-010.	Sector Notebook Data Refresh-1997 **	Seth Heminway	564-7017
	Government Series		
EPA/310-R-99-001.	Profile of Local Government Operations	John Dombrowski	564-7036

* Spanish translations available.

** This document revises compliance, enforcement, and toxic release inventory data for all profiles published in 1995.

Oil and Gas Extraction Industry
(SIC 13)
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ACS -	Automatic Casing Swab
AFS -	AIRS Facility Subsystem (CAA database)
AIRS -	Aerometric Information Retrieval System (CAA database)
AOR -	Area of Review (SDWA)
AOSC -	Association of Oilwell Servicing Contractors
API -	American Petroleum Institute
API ES -	American Petroleum Institute Environmental Statement
BAT -	Best Available Technology Economically Achievable
bbl -	Barrel (42 US gallons)
Bcf -	Billion Cubic Feet
BCT -	Best Conventional Pollutant Control Technology
bpd -	Barrels per Day
BIA -	Bureau of Indian Affairs (Department of the Interior)
BIFs -	Boilers and Industrial Furnaces (RCRA)
BLM -	Bureau of Land Management (Department of the Interior)
BMP -	Best Management Practice
BOD -	Biochemical Oxygen Demand
BOP -	Blowout Preventer
BPT -	Best Practicable Technology Currently Available
BS&W -	Basic Sediment and Water
BTEX -	Benzene, Toluene, Ethylbenzene and Xylene
CAA -	Clean Air Act
CAAA -	Clean Air Act Amendments of 1990
CERCLA -	Comprehensive Environmental Response, Compensation and Liability Act
CERCLIS -	CERCLA Information System
CFCs -	Chlorofluorocarbons
CFR -	Code of Federal Regulations
CGP -	Construction General Permit (CWA)
CO -	Carbon Monoxide
CO_2 -	Carbon Dioxide
COE -	Army Corps of Engineers (Department of Defense)
CZMA -	Coastal Zone Management Act
CWA -	Clean Water Act
DOC -	United States Department of Commerce
DOE -	United States Department of Energy
DOI -	United States Department of the Interior
E&P -	Exploration and Production
EIA -	Energy Information Administration (Department of Energy)
EIS -	Environmental Impact Statement
EOR -	Enhanced Oil Recovery
EPA -	United States Environmental Protection Agency
EPCRA -	Emergency Planning and Community Right-to-Know Act
ESA -	Endangered Species Act

EST -	Eastern Standard Time
FIFRA -	Federal Insecticide, Fungicide, and Rodenticide Act
FINDS -	Facility Indexing System
FLPMA-	Federal Land Policy and Management Act
FPSO-	Floating Production, Storage, and Offloading system
FR -	Federal Register
FRP -	Facility Response Plan
H_2S -	Hydrogen Sulfide
HAPs -	Hazardous Air Pollutants (CAA)
HSWA -	Hazardous and Solid Waste Amendments
IDEA -	Integrated Data for Enforcement Analysis
IOGCC -	Interstate Oil and Gas Compact Commission
IPAA -	Independent Petroleum Association of America
LDR -	Land Disposal Restrictions (RCRA)
LEPCs -	Local Emergency Planning Committees
MACT -	Maximum Achievable Control Technology (CAA)
Mcf -	Thousand Cubic Feet
MCLs -	Maximum Contaminant Levels
MCLGs -	Maximum Contaminant Level Goals
MFC -	Magnetic Fluid Conditioner
MIT -	Mechanical Integrity Test
MMPA -	Marine Mammal Protection Act
MMS -	Minerals Management Service (Department of the Interior)
MMTCE -	Million Metric Tons of Carbon Equivalent
MPRSA-	Marine Protection, Research, and Sanctuaries Act
MSDSs -	Material Safety Data Sheets
MSGP -	Multi-Sector General Permit (CWA)
NAAQS -	National Ambient Air Quality Standards (CAA)
NAICS -	North American Industrial Classification System
NCDB -	National Compliance Database (for TSCA, FIFRA, EPCRA)
NCP -	National Oil and Hazardous Substances Pollution Contingency Plan
NEC -	Not Elsewhere Classified
NEPA -	National Environmental Policy Act
NESHAP -	National Emission Standards for Hazardous Air Pollutants
$NICE^3$ -	National Industrial Competitiveness Through Energy, Environment and Economics
NO_2 -	Nitrogen Dioxide
NOI -	Notice of Intent
NORM -	Naturally Occurring Radioactive Material
NOT -	Notice of Termination
NPDES -	National Pollution Discharge Elimination System (CWA)
NPL -	National Priorities List
NRC -	National Response Center
NSPS -	New Source Performance Standards (CAA)
OAQPS -	Office of Air Quality Planning and Standards
OCS -	Outer Continental Shelf
OCSLA -	Outer Continental Shelf Lands Act

OECA -	Office of Enforcement and Compliance Assurance
OMB -	Office of Management and Budget
OOC -	Offshore Operators Committee
OPPTS -	Office of Prevention, Pesticides, and Toxic Substances
OSHA -	Occupational Safety and Health Administration
OSW -	Office of Solid Waste
OSWER -	Office of Solid Waste and Emergency Response
OW -	Office of Water
PAH -	Polyaromatic Hydrocarbon
PCB -	Polychlorinated Byphenyls
PCS -	Permit Compliance System (CWA Database)
PDC -	Polycrystalline Diamond Compact Drill Bit
PM10 -	Particulate Matter of 10 microns or less
PMN -	Premanufacture Notice
POP -	Problem Oil Pit
POTW -	Publicly Owned Treatments Works
PSD -	Prevention of Significant Deterioration (CAA)
PT -	Total Particulates
PTTC -	Petroleum Technology Transfer Council
RCRA -	Resource Conservation and Recovery Act
RCRIS -	RCRA Information System
RQ -	Reportable Quantity (CERCLA)
SARA -	Superfund Amendments and Reauthorization Act
SBF -	Synthetic-Based Drilling Fluid
SDWA -	Safe Drinking Water Act
SEPs -	Supplementary Environmental Projects
SERCs -	State Emergency Response Commissions
SIC -	Standard Industrial Classification
SIP -	State Implementation Plan
SO_2 -	Sulfur Dioxide
SPCC -	Spill Prevention Control and Countermeasure
STEP -	Strategies for Today's Environmental Partnership
SWPPP -	Storm Water Pollution Prevention Plan (CWA)
TRI -	Toxic Release Inventory
TRIS -	Toxic Release Inventory System
TSCA -	Toxic Substances Control Act
TSD -	Treatment Storage and Disposal
TSP -	Total Suspended Particulates
TSS -	Total Suspended Solids
UIC -	Underground Injection Control (SDWA)
USDW -	Underground Sources of Drinking Water (SDWA)
USFS -	United States Forest Service (Department of Agriculture)
USFWS -	United States Fish and Wildlife Service (Department of the Interior)
UST -	Underground Storage Tanks (RCRA)
VOCs -	Volatile Organic Compounds
WSPA -	Western States Petroleum Association

I. INTRODUCTION TO THE SECTOR NOTEBOOK PROJECT

I.A. Summary of the Sector Notebook Project

Environmental policies based upon comprehensive analysis of air, water and land pollution (such as economic sector, and community-based approaches) are becoming an important supplement to traditional single-media approaches to environmental protection. Environmental regulatory agencies are beginning to embrace comprehensive, multi-statute solutions to facility permitting, compliance assurance, education/outreach, research, and regulatory development issues. The central concepts driving the new policy direction are that pollutant releases to each environmental medium (air, water and land) affect each other, and that environmental strategies must actively identify and address these interrelationships by designing policies for the "whole" facility. One way to achieve a whole facility focus is to design environmental policies for similar industrial facilities. By doing so, environmental concerns that are common to the manufacturing of similar products can be addressed in a comprehensive manner. Recognition of the need to develop the industrial ?sector-based” approach within the EPA Office of Compliance led to the creation of this document.

The Sector Notebook Project was initiated by the Office of Compliance within the Office of Enforcement and Compliance Assurance (OECA) to provide its staff and managers with summary information for eighteen specific industrial sectors. As other EPA offices, states, the regulated community, environmental groups, and the public became interested in this project, the scope of the original project was expanded. The ability to design comprehensive, common sense environmental protection measures for specific industries is dependent on knowledge of several interrelated topics. For the purposes of this project, the key elements chosen for inclusion are: general industry information (economic and geographic); a description of industrial processes; pollution outputs; pollution prevention opportunities; federal statutory and regulatory framework; compliance history; and a description of partnerships that have been formed between regulatory agencies, the regulated community and the public.

For any given industry, each topic listed above could alone be the subject of a lengthy volume. However, in order to produce a manageable document, this project focuses on providing summary information for each topic. This format provides the reader with a synopsis of each issue, and references where more in-depth information is available. Text within each profile was researched from a variety of sources, and was usually condensed from more detailed sources pertaining to specific topics. This approach allows for a wide coverage of activities that can be further explored based upon the references listed at the end of this profile. As a check on the information included, each notebook went through an external document review process. The Office of Compliance appreciates the efforts of all those that participated in this process and enabled us to develop more complete, accurate and up-to-date summaries. Many of those who reviewed this notebook are listed as contacts in Section IX and may be sources of additional information. The individuals and groups on this list do not necessarily concur with all statements within this notebook.

I.B. Additional Information

Providing Comments

OECA's Office of Compliance plans to periodically review and update the notebooks and will make these updates available both in hard copy and electronically. If you have any comments on the existing notebook, or if you would like to provide additional information, please send a hard copy and computer disk to the EPA Office of Compliance, Sector Notebook Project (2223-A), 401 M St., SW, Washington, DC 20460. Comments can also be sent via the web page or to notebook@epamail.epa.gov.

Adapting Notebooks to Particular Needs

The scope of the industry sector described in this notebook approximates the national occurrence of facility types within the sector. In many instances, industries within specific geographic regions or states may have unique characteristics that are not fully captured in these profiles. The Office of Compliance encourages state and local environmental agencies and other groups to supplement or re-package the information included in this notebook to include more specific industrial and regulatory information that may be available. Additionally, interested states may want to supplement the "Summary of Applicable Federal Statutes and Regulations" section with state and local requirements. Compliance or technical assistance providers may also want to develop the "Pollution Prevention" section in more detail. Please contact the appropriate specialist listed on the opening page of this notebook if your office is interested in assisting us in the further development of the information or policies addressed within this volume. If you are interested in assisting in the development of new notebooks, please contact the Office of Compliance at (202) 564-2395.

II. INTRODUCTION TO THE OIL AND GAS EXTRACTION INDUSTRY

This section provides background information on the size, geographic distribution, employment, production, sales, and economic condition of the oil and gas extraction industry. Facilities described within the document are described in terms of their Standard Industrial Classification (SIC) codes.

II.A. Introduction, Background, and Scope of the Notebook

This industry sector profile provides an overview of the oil and gas industry as listed under SIC code 13. The SIC code 13 encompasses the oil and gas extraction process from the exploration for petroleum deposits up until the transportation of the product from the production site. There are five major groups within SIC code 13:

SIC 1311*. *Crude petroleum and natural gas. Establishments in this industry are primarily involved in the operation of oil and gas field properties. Establishments under this category might also perform exploration for crude oil and natural gas, drill and complete wells, and separate the crude oil and natural gas components from the natural gas liquids and produced fluids.

SIC 1321. Natural gas liquids. This industry is comprised of establishments that separate natural gas liquids from crude oil and natural gas at the site of production. Examples of these gases are propane and butane. Natural gas liquids producers that remove additional material at petroleum refineries are classified under SIC code 29, and establishments that recover other salable contaminants such as helium are classified under SIC code 28.

SIC 1381. Drilling oil and gas wells. This industry is made up of establishments that drill wells on a contract or fee basis.

SIC 1382. Oil and gas field exploration services. Establishments in this industry perform geological, geophysical and other exploration services for oil and gas on a contract or fee basis.

SIC 1389. Oil and gas field services, not elsewhere classified (NEC). Establishments in this industry perform services on a contract or fee basis that are not elsewhere classified. These include the preparation of drilling sites by building foundations and excavating pits, the completion of wells and preparation for production, and the performing of maintenance.

While this notebook covers all of the SIC codes listed above, the diverse nature of the industries will not allow a detailed description of each. Since the service industries (SIC codes 1381, 1382, and 1389) and natural gas liquids industry (SIC code 1321) are tied to the economic, geographic, and production trends of SIC code 1311, most attention is focused on the crude petroleum and natural gas industry. Although certain products under these SIC codes may not be specifically mentioned, the sector-wide economic, pollutant output, and enforcement and compliance data in this notebook covers all establishments involved with oil and gas extraction.

SIC codes were established by the Office of Management and Budget (OMB) to track the flow of goods and services within the economy. OMB is in the process of changing the SIC code system to a system based on similar production processes called the North American Industrial Classification System (NAICS). In the NAICS, the SIC codes for the oil and gas extraction industry correspond to the following NAICS codes:

1987 SIC	U.S. SIC Description	1997 NAICS	NAICS Description
1311	Crude Petroleum and Natural Gas	211111	Crude Petroleum and Natural Gas Extraction
1321	Natural Gas Liquids	211112	Natural Gas Liquid Extraction
1381	Drilling Oil and Gas Wells	213111	Drilling Oil and Gas Wells
1382	Oil and Gas Field Exploration Services	54136	Geophysical Surveying and Mapping Services
		213112	Support Activities for Oil and Gas Operations
1389	Oil and Gas Field Services, NEC	213112	Support Activities for Oil and Gas Operations

II.B. Characterization of the Oil and Gas Extraction Industry

II.B.1. Product Characterization

The primary products of the industry are crude oil, natural gas liquids, and natural gas. Crude oil is a mixture of many different hydrocarbon compounds that must be processed to produce a wide range of products. U.S. refinery processing of crude oil yields, on average, motor gasoline (approximately 40 percent), diesel fuel and home heating oil (20 percent), jet fuels (10 percent), waxes, asphalts and other nonfuel products (5 percent), feedstocks for the petrochemical industry (3 percent), and other lesser components (U.S.

Department of Energy, Energy Information Administration (EIA), 1999). Volumes of oil and refined products typically are reported in barrels (bbl), which are equal to 42 gallons.

When crude oil is first brought to the surface, it may contain~~ed~~ in a mixture of natural gas and produced fluids such as salt water and both dissolved and suspended solids. On land (and at many offshore operations) Natural gas is separated at the well site and is processed for sale if natural gas pipelines (or other transportation vehicles) are nearby, or is flared as a waste (at onshore operations only). Water (which can be more than 90 percent of the fluid extracted in older wells) is separated out, as are solids. Only about one-third of the production platforms offshore in the Gulf of Mexico separate water. The other offshore Gulf platforms transport full well stream, sometimes great distances, to central processing facilities. The crude oil is at least 98 percent free of solids after it passes through this onsite treatment and is prepared for shipment to storage facilities and ultimately refineries (Sittig, 1978).

Natural gas can be produced from oil wells (called *associated gas*), or wells can be drilled with natural gas as the primary objective (called *non-associated gas*). Methane is the predominant component of natural gas (approximately 85 percent), but ethane (10 percent), propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed; these are often separated and processed as natural gas liquids.

Less frequently, oil and gas can be produced by other methods. Oil can be found in tar sands, which are porous rock (sandstone) structures on the surface to 100 meters deep. The material is fairly viscous, and also is fairly high in sulfur and metals. Although the Athabasca region in Canada is the primary area of significant tar sand mining, there are some deposits in the western United States.

Oil may also be extracted from oil shale. These deposits may be 10 to 800 feet below the surface, and can be removed by surface mining or subsurface excavation. The oil, in a highly viscous form called *kerogen*, is usually heated to allow it to flow. Because only approximately 30 gallons (less than a barrel) are produced per ton of shale, the process is costly, and the oil shale mining industry is currently only a minor contribution to the domestic oil supply.

A small but increasingly significant source of natural gas is coalbed methane. In all coal deposits, methane is found as a byproduct of the coalification process and is loosely bound to coal surface areas. This methane historically was considered a safety hazard in the coal mining process and was vented, but recently it has been recovered in conjunction with mining or produced independently via wells in deposits that are too deep for mining. Generally, coalbed methane is collected by drilling a well similar to those used for conventional oil and gas deposits, but with some adaptations to accommodate mining operations and different rock characteristics (EPA, 1992). In 1997, coalbed methane production accounted for six percent of the total U.S. natural gas production (EIA, 1998).

Methane hydrates are another form of natural gas, for which economically viable recovery methods are still in development. Methane hydrates are structures in which methane molecules are trapped within a lattice of ice. They are found principally in cold and/or pressurized conditions: on land in permafrost regions, or beneath the ocean at depths greater than 1,500 feet below the water surface. These eventually could be an immense resource; estimated amounts of methane in these structures in the United States is 200,000 trillion cubic feet, compared to an estimated 1,400 trillion cubic feet in conventional natural gas deposits. A goal of the U.S. Department of Energy methane hydrates research program is to develop a commercial production system by the year 2015 (U.S. DOE, 1998).

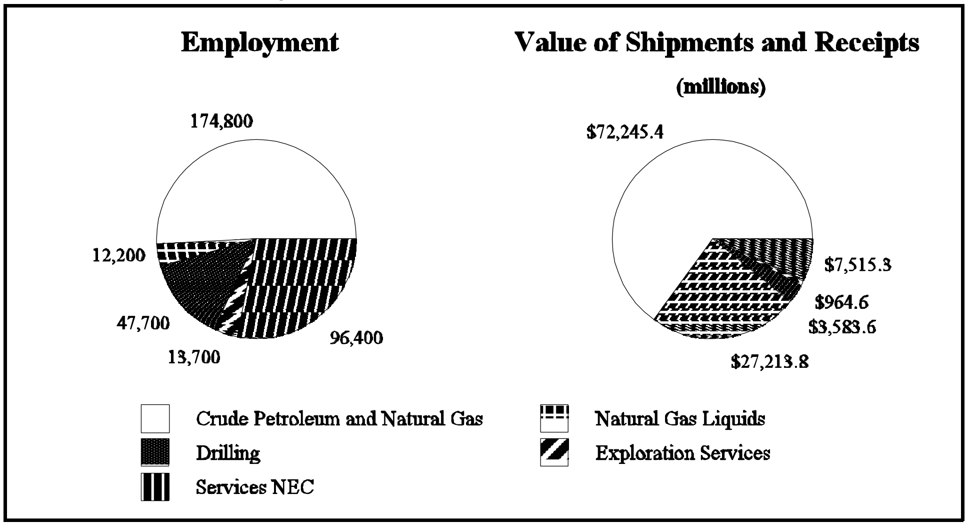
II.B.2. Industry Size and Distribution

The oil and gas extraction industry is an important link in the energy supply of the United States. Petroleum and natural gas supply 65 percent of the energy consumed in the United States, and domestic producers supply approximately 40 percent of the petroleum and 90 percent of the natural gas (EIA and Independent Petroleum Association of America (IPAA), 1999). According to the 1992 Census of Mining Industries, the industry employed 345,000 people and had yearly revenues of $112 billion.

Several factors influence the size of the industry, including technology development and crude oil prices (which are set in world markets) (EIA, 1999). Employment in the industry is also affected by the recent trend in mergers and consolidation among companies in the industry.

Within the overall oil and gas extraction industry group (SIC code 13), SIC 1311 (crude petroleum and natural gas) is the largest. As shown in Figure 1, this industry employs half of the total workers in this SIC group, and accounts for about 60 percent of the sales. SIC code 1389 (services not elsewhere classified) is the next largest employer, but SIC code 1321 (natural gas liquids) is more significant with respect to sales.

Figure 1: Employment and Value of Shipments and Receipts in the Oil and Gas Industry



Source: *1992 Census of Mineral Industries*, U.S. Department of Commerce, 1995.

The major oil- and gas-producing areas in the United States are in the Gulf of Mexico region (onshore and offshore), California, and Alaska (see Figure 2). The Gulf of Mexico and surrounding land in particular is the most concentrated area of production; in 1998, Texas (onshore and offshore) produced 23 percent of the nation's crude oil, Louisiana produced 5 percent, and 14 percent was produced in the Federal offshore region.[1]

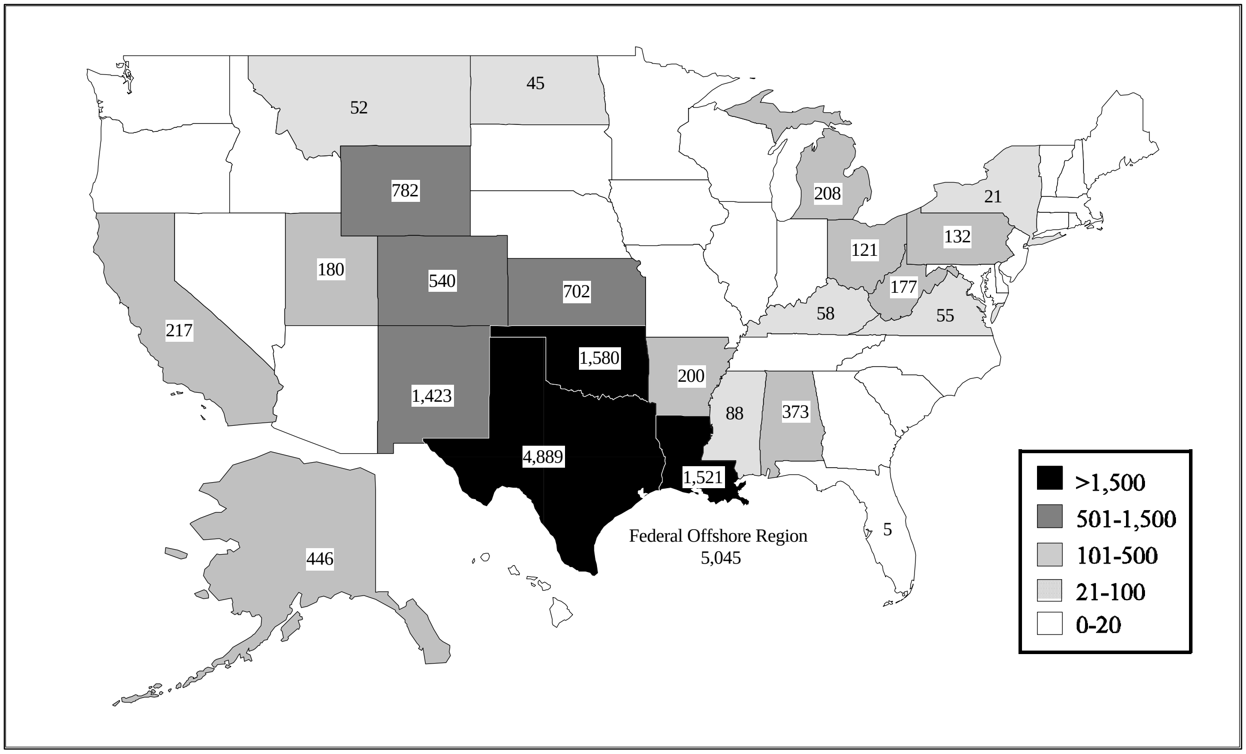
The geographic distribution is similar for natural gas; Texas, Louisiana, and the Gulf of Mexico are the major producing locations (Figure 3). New Mexico, Oklahoma, Wyoming, and Kansas are also important gas-producing states, while California and Alaska are less important with respect to natural gas production than they are for crude oil.

[1] The Federal Offshore Region, or Outer Continental Shelf (OCS), is seaward of State jurisdiction (3 nautical miles, or approximately 3.3 statute miles, from an established baseline except for Texas and the Gulf coast of Florida, for which the boundary is 3 marine leagues, or approximately 10 statute miles), and landward of a line defined by international law at a minimum of 200 nautical miles (MMS, 1997) (See p101 for more details).

Figure 2: 1996 U.S. Crude Oil Production (Million Barrels per Year)

Note: Small quantities are also produced in Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

Figure 3: 1996 U.S. Natural Gas Production (Billion Cubic Feet per Year)



Note: Small quantities are also produced in Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

The oil and gas industry has a unique standing for census purposes because of the sheer number of wells in the country. For the purposes of simplifying reporting procedures under SIC code 1311, the census defines an establishment as all activities of an operating company in an entire state. Therefore, these data give no information on the number of individual wells. Data collected by the Independent Petroleum Association of America, however, indicated that in 1997 there were 573,504 active wells extracting primarily crude oil, and 303,724 wells producing primarily natural gas in the United States (IPAA, 1999).

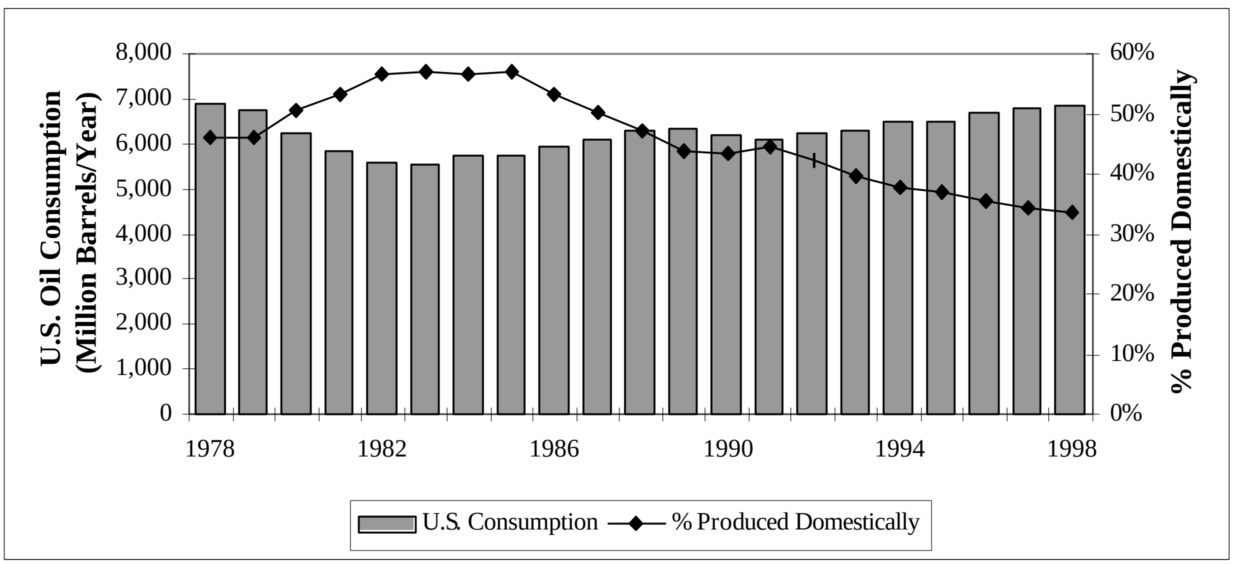
Another unique aspect of the industry is the marginal nature of many operations. Oil and gas wells can have very long lives (20 years or more); some wells drilled in the early years of this century are still producing, but only in small volumes. Wells typically have higher production in the early years, then decline and can level off at a low level of production that can be sustained for a long period (API, 1999). Wells that produce less than 10 barrels of oil per day are called "stripper wells." As of 1997, there were 436,000 active stripper wells (76 percent of all active domestic wells) producing an average of 2.2 barrels each daily. Together stripper wells account for about 15 percent of domestic production (IPAA, 1999).

II.B.3. Economic Trends

Domestic Consumption

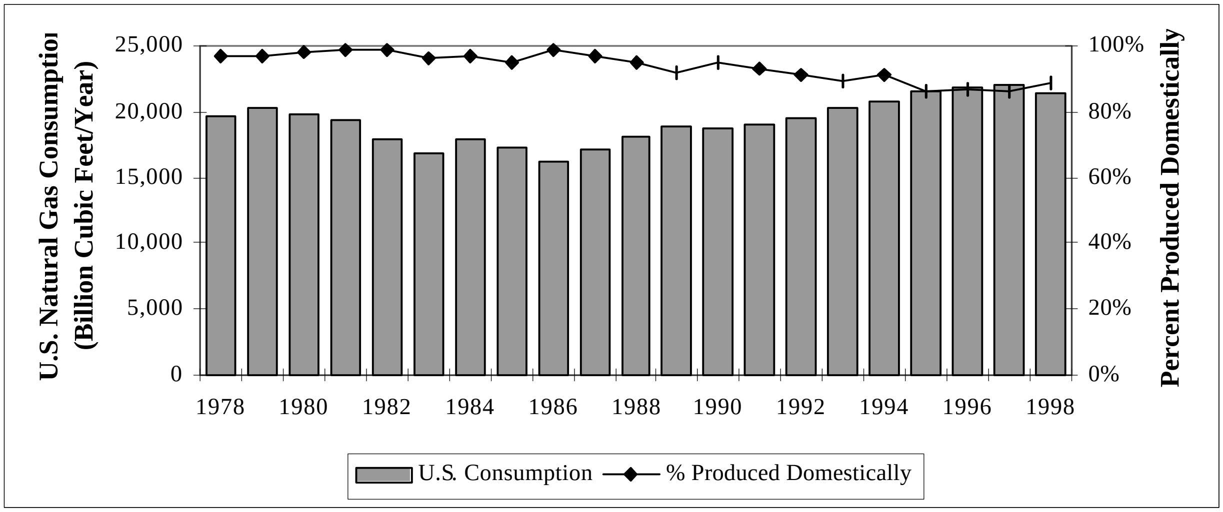
The consumption of oil and gas in the United States is closely linked to the overall economy of the country. Between 1990 and 1998, crude oil consumption increased approximately 1.4 percent each year, and natural gas consumption increased at a rate of 2.0 percent per year. The rate of natural gas consumption is expected to continue growing, mostly at the expense of coal. Natural gas is expected to become an important source of energy in the future and will be accelerated by government policies and the development of the natural gas transportation infrastructure. In the past several years, however, the percent of the domestic consumption of both oil and gas met by domestic producers generally has decreased (Figures 4 and 5).

Figure 4: U.S. Oil Consumption and Percent Produced Domestically



Source: EIA and IPAA, 1999.

Figure 5: U.S. Natural Gas Consumption and Percent Produced Domestically

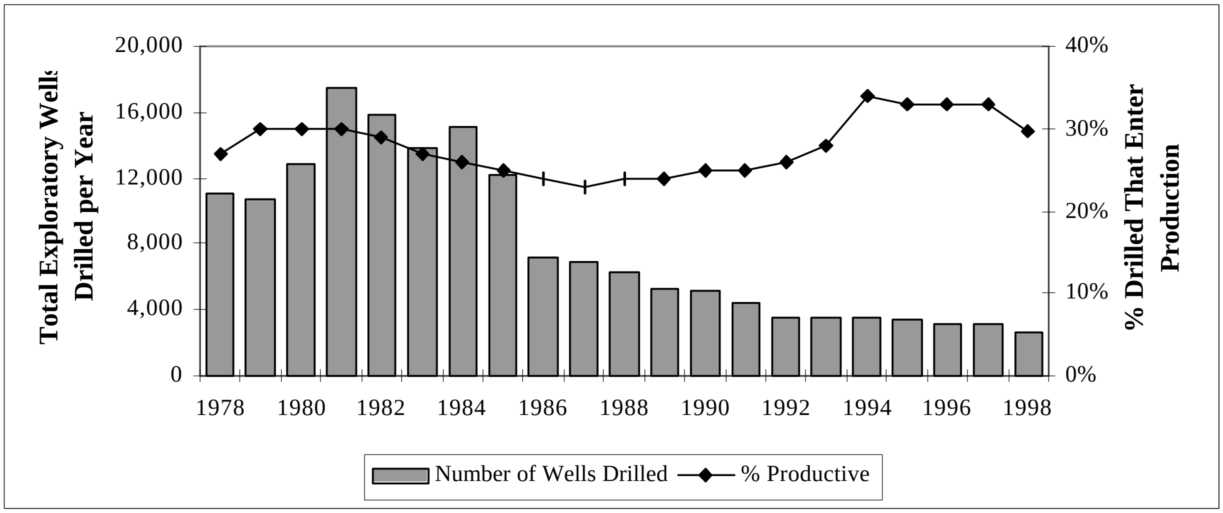


Source: EIA and IPAA, 1999.

Exploration and Reserves

The industry is exhibiting a general trend in exploration from domestic to foreign locations. In 1986, U.S. petroleum companies spent $17 billion on exploration and development within the United States and $7.5 billion abroad. In 1995, these firms spent $12.4 billion in the United States and $13.2 billion abroad (U.S. Department of Commerce (U.S. DOC), 1998). This shift in funds has placed an emphasis on drilling exploratory wells only at the most promising sites in the U.S. The results can be seen in Figure 6; many fewer exploratory wells are being drilled, but the success rate is higher.

Figure 6: Number of Exploratory Wells Drilled and Percent That Enter Production



Note: Includes both oil and natural gas wells.
Source: American Petroleum Institute, 1999.

The most active areas of exploration are the Gulf of Mexico and Alaska. In the Gulf of Mexico, the development of technology that facilitates drilling in deeper water (including floating structures, drillships and subsea completions) has made it more feasible to explore deep water sites. Another new source for potential reserves[2] is in Alaska, where roughly 87 percent of the Northeast National Petroleum Reserve was opened in 1998 for exploration and leasing (DOI, 1998). Developments such as these temporarily have boosted hydrocarbon reserves above production levels. In 1997, for the first time in a decade, crude oil reserves were added at a level greater than the amount depleted through production. However, it is expected that in the future reserves will again decline relative to production (EIA, 1998).

Natural gas exploration efforts in the United States have been more successful than crude oil exploration at keeping pace with production. Between 1994 and 1997, the industry added more reserves than it extracted in production. In 1997, about 64 percent of the new reserves of natural gas were found in the Gulf of Mexico Federal Offshore region and Texas (EIA, 1998).

Domestic Production and Prices

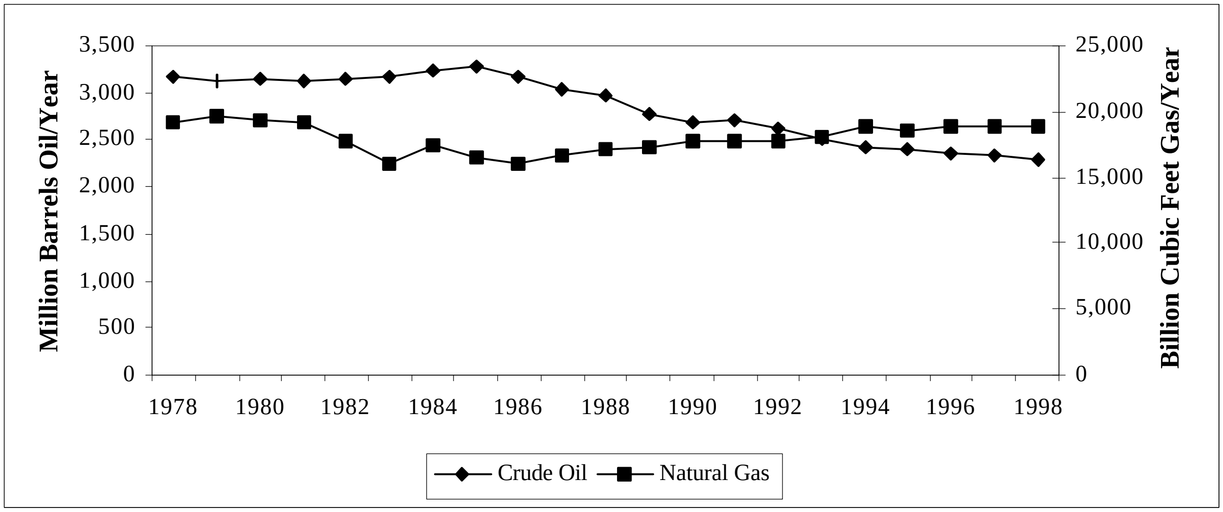
Production of crude oil is showing a decreasing trend, and natural gas production is showing an increasing trend. As shown in Figure 7, crude oil

[2] The Energy Information Administration of the U.S. Department of Energy defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (EIA, 1998).

production is decreasing at an approximate rate of 1.5 percent per year. Leading the decline is Alaska, where production has declined approximately three percent per year in the past decade and six percent in 1997.

The production of natural gas, however, has been increasing steadily. Historically, growth has been about 1 percent per year, and is expected to grow at a rate of 1.6 percent per year through 2002 (U.S. DOC, 1998).

Figure 7: Domestic Crude Oil and Natural Gas Production

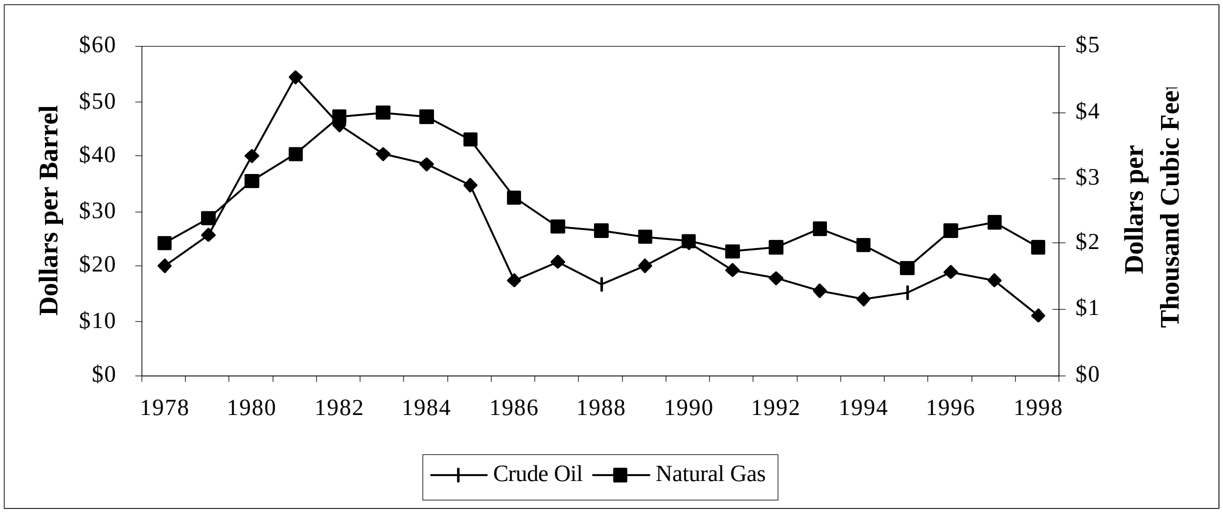


Source: EIA and IPAA, 1999.

As shown in Figure 8, the prices of both oil and gas have been quite volatile during the period between 1978 and 1997. In constant 1998 dollars, the wellhead price of crude oil has ranged between \$10 and \$54 per barrel. In 1998 and early 1999, prices were near \$10 per barrel, but by August 1999 the price rebounded to over \$20 per barrel (EIA, 1999).

Natural gas prices also have fluctuated. Wellhead prices reached a low point of \$1.62 per thousand cubic feet in 1995, but increased in the subsequent two years. Prices of natural gas are expected to increase faster than those of oil through 2002, but still less than the rate of inflation (U.S. DOC, 1998).

Figure 8: Wellhead Crude Oil and Natural Gas Prices, Fixed 1998 Dollars



Source: EIA and IPAA, 1999.

III. INDUSTRIAL PROCESS DESCRIPTION

This section describes the major industrial processes within the oil and gas extraction industry, including the materials and equipment used and the processes employed. Specifically, this section contains a description of commonly used drilling and production processes, associated raw materials, the byproducts produced or discharges released, and the materials either recycled or transferred off-site. This discussion also provides a concise description of both the production and the potential fate of wastes produced in each process.

The section is designed for those interested in gaining a general understanding of the industry, and for those interested in the inter-relationship between the industrial process and the topics described in subsequent sections concerning waste outputs, pollution prevention opportunities, and federal regulations. This section does not attempt to replicate published engineering information that is available for this industry. Refer to Section IX for a list of reference documents that are available to supplement this document.

III.A. Industrial Processes in the Oil and Gas Extraction Industry

The oil and gas extraction industry can be classified into four major processes: (1) exploration, (2) well development, (3) production, and (4) site abandonment. Exploration involves the search for rock formations associated with oil or natural gas deposits, and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field, and involves the construction of one or more wells from the beginning (called *spudding*) to either abandonment if no hydrocarbons are found, or to well completion if hydrocarbons are found in sufficient quantities.

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. Production sites often handle crude oil from more than one well. Oil is nearly always processed at a refinery; natural gas may be processed to remove impurities either in the field or at a natural gas processing plant.

Finally, site abandonment involves plugging the well(s) and restoring the site when a recently-drilled well lacks the potential to produce economic quantities of oil or gas, or when a production well is no longer economically viable.

Two ancillary processes are also discussed in this section because they have significant economic and environmental implications. Maintenance of the well and reservoir is important in sustaining the safety and productivity of the operation and in ensuring protection of the environment. Spill mitigation is important in the oil and gas production industry because spills and other types of accidents can have serious implications for worker safety and the environment.

III.A.1. Exploration

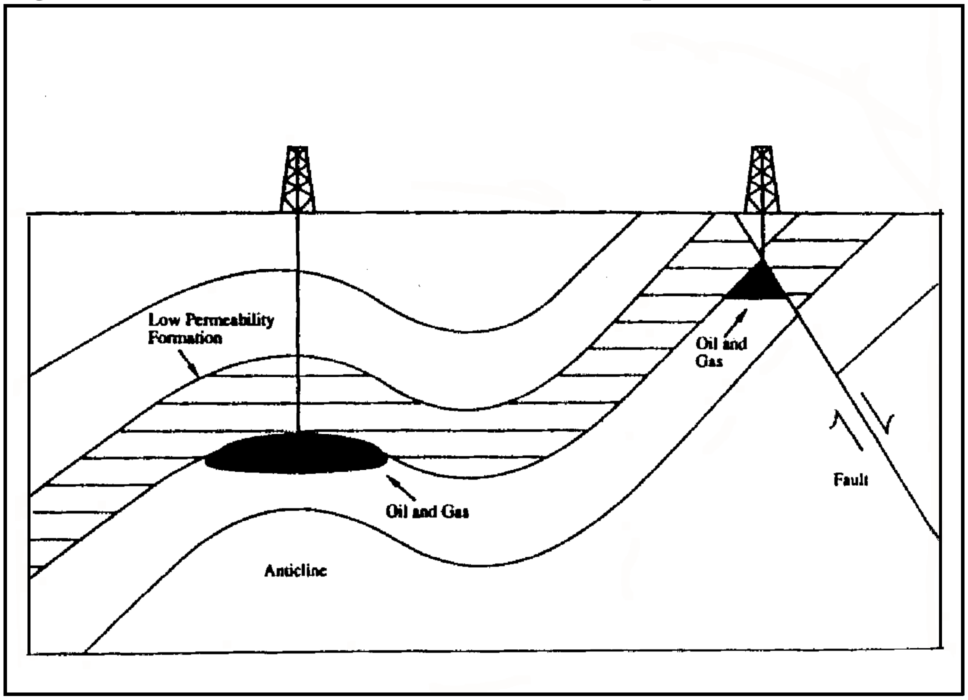
Oil and natural gas deposits are located almost exclusively in sedimentary rock and are often associated with certain geological structures. Geophysical exploration is the process of locating these structures in the subsurface via methods that fall under the category of remote sensing. In particular, common hydrocarbon-containing structures are those where a relatively porous rock has an overlying low-permeability rock that would trap the hydrocarbons (Berger and Anderson, 1992). Two common structural traps are found in Figure 9: anticlines are upward folds in the rock layers, while faults are fractures in the Earth's surface where layers are shifted.

Geophysicists search for these structures by taking advantage of the fact that seismic waves will travel through, bend, absorb, and reflect differently off of various layers of rock (Berger and Anderson, 1992). Geophysicists generate these seismic waves at the earth's surface, and measure the reflected seismic waves with a series of sensors known as geophones. Seismic waves can be generated by a variety of sources ranging from explosives that are detonated in holes drilled below the surface, to land vibroseis and marine airguns. Land vibroseis is typically used near populated areas and near sensitive environmental areas where detonations are not desirable. In the vibroseis process, trucks are used to drop a heavy weight on hard surfaces such as paved roads in order to create seismic waves.

In marine locations, explosives are less effective and have deleterious environmental impacts. In addition, vibroseis is impractical in water that is hundreds of feet deep. Seismic energy is therefore created by an airgun, a large device that can be emptied of air and water to create a vacuum. Seismic waves are created when water is allowed into the device at a very fast rate. It should be stressed that geophysical remote sensing cannot identify oil or gas accumulations directly; it can only indicate the potential for reserves via the presence or absence of certain rock characteristics that may be worthy of exploration.

After a site has been judged to have a reasonable chance of discovering a sufficient amount of hydrocarbons an exploratory well is drilled. It should be noted that although seismic exploration technology is constantly improving, it is not perfect. The only true way to discover the presence and quantity of petroleum is by drilling a well into the formation or structure suspected of containing hydrocarbons.

Figure 9: Common Oil and Gas Structural Traps



Source: EPA, 1992.

III.A.2. Well Development

Drilling

During the drilling process, wellsite geologists will augment the remote geophysical data with wireline logs, which are taken by means of devices lowered into the wellbore with wires. Wireline logs include several types of measurements that help to characterize the depths and thickness of subsurface formations and the type of fluids that they may contain. As an example, one type of log analyzes the resistance of the formation to electrical current, which helps to indicate the type of fluid and the porosity of the formation. For exploratory wells, mud logs may also be developed, which document the drill rate, types of rocks encountered, and any hydrocarbons encountered. The range of depths of well holes, or *wellbores,* is anywhere between 1,000 and 30,000 feet, with an average depth of all U.S. wells drilled in 1997 of 5,601 feet (API, 1998a).

For both onshore and offshore sites, the subterranean aspects of the drilling procedure are very similar. The drill bit is the component in direct contact with the rock at the bottom of the hole, and increases the depth of the hole by chipping off pieces of rock. The bit may be anywhere from three and three-fourths inches to two feet in diameter, and is usually studded with hardened steel or diamond. The selection of the drill bit can vary, depending on the type of rock and desired drilling speed. For example, a large-toothed steel bit may be used if the formation is soft and speed is important, while a diamond-studded bit may be used for hard formations or when a long drill life is desired (Kennedy, 1983). The drill bit is connected to the surface by several segments of hollow pipe, which together are called the *drill string*. The drill string is usually about 4 inches in diameter; drilling fluid is pumped down through its center and returns to the surface through the space, called the *annulus*, between the drill string and the rock formations or casing.

Drilling Fluids

Drilling fluid is an important component in the drilling process. A fluid is required in the wellbore to: (1) to cool and lubricate the drill bit; (2) remove the rock fragments, or *drill cuttings,* from the drilling area and transport them to the surface; (3) counterbalance formation pressure to prevent formation fluids (i.e. oil, gas, and water) from entering the well prematurely, and (4) prevent the open (uncased) wellbore from caving in (Berger and Anderson, 1992; Souders, 1998). Different properties may be required of the drilling fluid, depending upon the drilling conditions. For example, a higher-density fluid may be needed in high-pressure zones, and a more temperature-resistant fluid may be desired in high-temperature conditions. While drilling fluid may be a gas or foam, liquid-based fluids (called *drilling muds*) are used for approximately 93 percent of wells (API, 1997). In addition to liquid, drilling muds usually contain bentonite clay that increases the viscosity and alters the density of the fluid. Drilling mud may also contain additional additives that alter the properties of the fluid. The most significant additives are described later in this section. The American Petroleum Institute (API) environmental guidance document "Waste Management in Exploration and Production Operations," (API E5) considers the three general categories of drilling fluid (muds) to be water-based, oil-based, and synthetic-based. Synthetic-based muds are used as substitutes for oil-based muds, but also may be an advantageous replacement for water-based muds in some situations.

Water-based muds are used most frequently. The base may be either fresh or salt water, for onshore and offshore wells, respectively. The primary benefit of water-based muds is cost; they are the least expensive of the major types of drilling fluids, and in general they are less expensive to use since the resultant drilling waste can be discharged onsite provided these wastes pass regulatory requirements (EPA, 1999). The significant drawback with water-based muds is their limited lubricity and reactivity with some shales. In deep holes or high-angle directional drilling, water-based muds are not able to supply sufficient lubricity to avoid sticking of the drill pipe. Reactivity with clay shale can cause the destabilization of the wellbore. In these cases, oil-based and synthetic muds are needed.

In 1993 EPA estimated that about 15 percent of wells drilled deeper than 10,000 feet used some oil-based muds (USEPA, 1993b). Oil-based muds are composed primarily of diesel oil or mineral oil and are therefore more expensive than water-based muds. This higher cost, which includes the added burden of removing the oil from drill cuttings, and the required disposal options make oil-based muds a less frequently used option. Oil-based muds are well suited for the high temperature conditions found in deep wells because oil components have a higher boiling point than water, and oil-based muds can avoid the pore-clogging that may occur with water-based muds. Also oil-based muds are used when drilling through reactive (or high pressure) shales, high-angle directional drilling, and drilling in deep water. These situations encountered while drilling can slow down the drilling rate, increase drilling costs or even be impossible if water-based muds are used. In cases when oil-based muds are necessary, the upper section of a well generally is drilled with water-based muds and the conversion is made to oil-based mud when the situation requires it. It is predicted that since the industry trend is toward deeper wells, oil-based muds may become more prominent. However, because oil-based muds and their cuttings can not be discharged this may not be the case.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these fluids are called synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkylbenzenes, and others. Other oleaginous materials have also been developed for this purpose, such as enhanced mineral oils and non-synthetic paraffins. Industry developed synthetic-based fluids with these synthetic and non-synthetic oleaginous materials as the base fluid to provide the drilling performance characteristics of traditional oil-based fluids based on diesel and mineral oil, but with the potential for lower environmental impact and greater worker safety through lower toxicity, elimination of Polyaromatic hydrocarbons (PAH), faster biodegradability, lower bioaccumulation potential and in some drilling situations decreased drilling waste volume (FR 66086, December 16, 1996).

On land air and foam fluids may be used in drilling wells. These fluids are less viscous than drilling muds, and can enter smaller pores more easily. They are used when a higher rate of penetration into the formation is desired. Because air is less dense than a liquid, however, these fluids cannot exert the same pressure in the hole as liquid, and their viscosity can be altered if drilling encounters liquid in the formation. For this reason, air and foam fluids are used only in relatively low-pressure and water-free drilling locations, but are preferred in these situations because these fluids are much less expensive than other fluids (Kennedy, 1983; Souders, 1998). Air and foam fluids currently are used in the drilling of about seven percent of the wells in the United States (API, 1997).

Drilling muds typically have several additives. (Air and foam fluids typically do not contain many additives because the additives are either liquid or solid, and will not mix with air and foam drilling fluids.) The following is a list of the more significant additives:

- Weighting materials, primarily barite (barium sulfate), may be used to increase the density of the mud in order to equilibrate the pressure between the wellbore and formation when drilling through particularly pressurized zones. Hematite (Fe_2O_3) sometimes is used as a weighting agent in oil-based muds (Souders, 1998).

- Corrosion inhibitors such as iron oxide, aluminum bisulfate, zinc carbonate, and zinc chromate protect pipes and other metallic components from acidic compounds encountered in the formation.

- Dispersants, including iron lignosulfonates, break up solid clusters into small particles so they can be carried by the fluid.

- Flocculants, primarily acrylic polymers, cause suspended particles to group together so they can be removed from the fluid at the surface.

- Surfactants, like fatty acids and soaps, defoam and emulsify the mud.

- Biocides, typically organic amines, chlorophenols, or formaldehydes, kill bacteria that may produce toxic hydrogen sulfide gas.

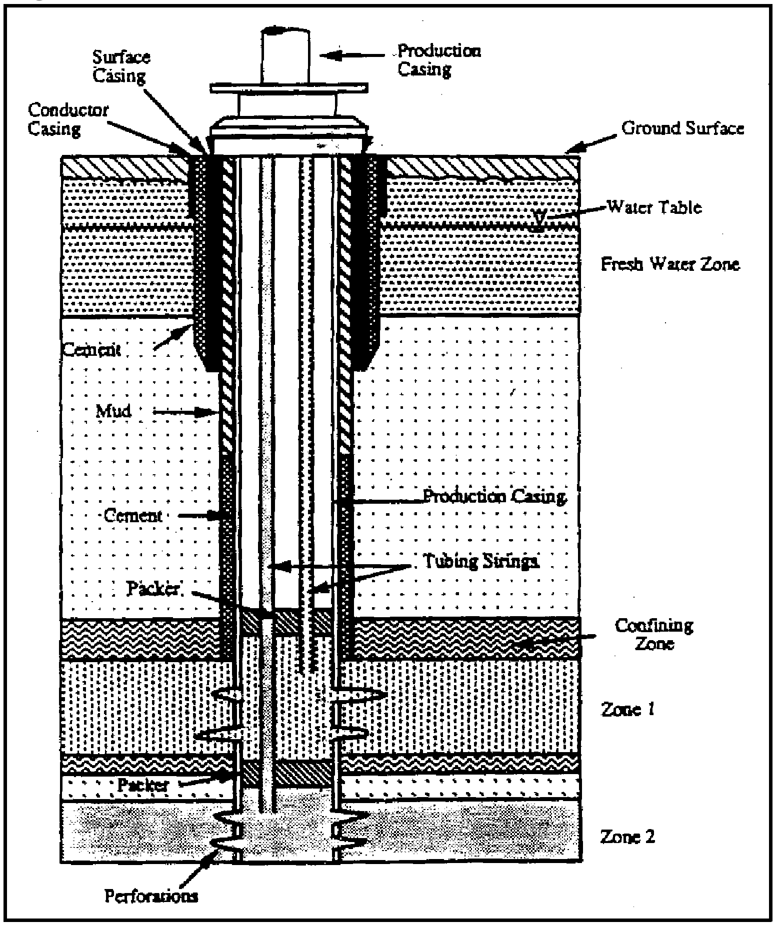
- Fluid loss reducers include starch and organic polymers and limit the loss of drilling mud to under-pressurized or high-permeability formations (EPA, Office of Solid Waste, 1987).

Casing

As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. The casing also isolates water bearing and hydrocarbon bearing zones. As shown in Figure 10, three or four separate casing “strings” (lengths of tubing of a given diameter) may be used in intermediate-depth wells. In locations where surface soils may cave in during drilling, a "conductor" casing may be placed at the surface, extending only twenty to one hundred feet from the surface. This string is often placed prior to the commencement of drilling with a pile driver (Berger and Anderson, 1992). The next string, or "surface" casing, begins at the surface and may penetrate two thousand to three thousand feet. Its primary purpose is to protect the surrounding fresh-water aquifer(s) from the incursion of oil or brine from greater depths. The "intermediate" string begins at the surface and ends within a couple thousand feet of the bottom of the wellbore. This section prevents the hole from caving in and facilitates the movement of equipment used in the hole, e.g., drill strings and logging tools. The final "production" string extends the full length of the wellbore and encases the downhole production equipment. Shallow wells may have only two casing strings, and deeper wells may have multiple intermediate casings. After each casing string has been installed, cement is forced out through the bottom of the casing up the annulus to hold it in place and surface casing is cemented to the surface. Casing is cemented to prevent migration of fluids behind the casing and to prevent communication of higher pressure productive formations with lower pressure non-productive formations. Additional features and equipment shown in Figure 10 will be installed during the completion process for production: perforations will allow reservoir fluid to enter the wellbore; tubing strings will carry the fluid to the surface; and packers (removable plugs) may be installed to isolate producing zones.

Casing is important for both the drilling and production phases of operation, and must therefore be designed properly. It prevents natural gas, oil, and associated brine from leaking out into the surrounding fresh-water aquifer(s), limits sediment from entering the wellbore, and facilitates the movement of equipment up and down the hole. Several considerations are involved in planning the casing. First, the bottom of the wellbore must be large enough to accommodate any pumping equipment that will be needed either upon commencement of pumping, or in the later years of production. Also, unusually pressurized zones will require thicker casing in that immediate area. Any casing strings that must fit within this string must then be smaller, but must still accommodate the downhole equipment. Finally, the driller is encouraged to keep the hole size to a minimum; as size increases, so does cost and waste.

Figure 10: Cross Section of a Cased Well



Source: EPA, 1992.

Drilling Infrastructure

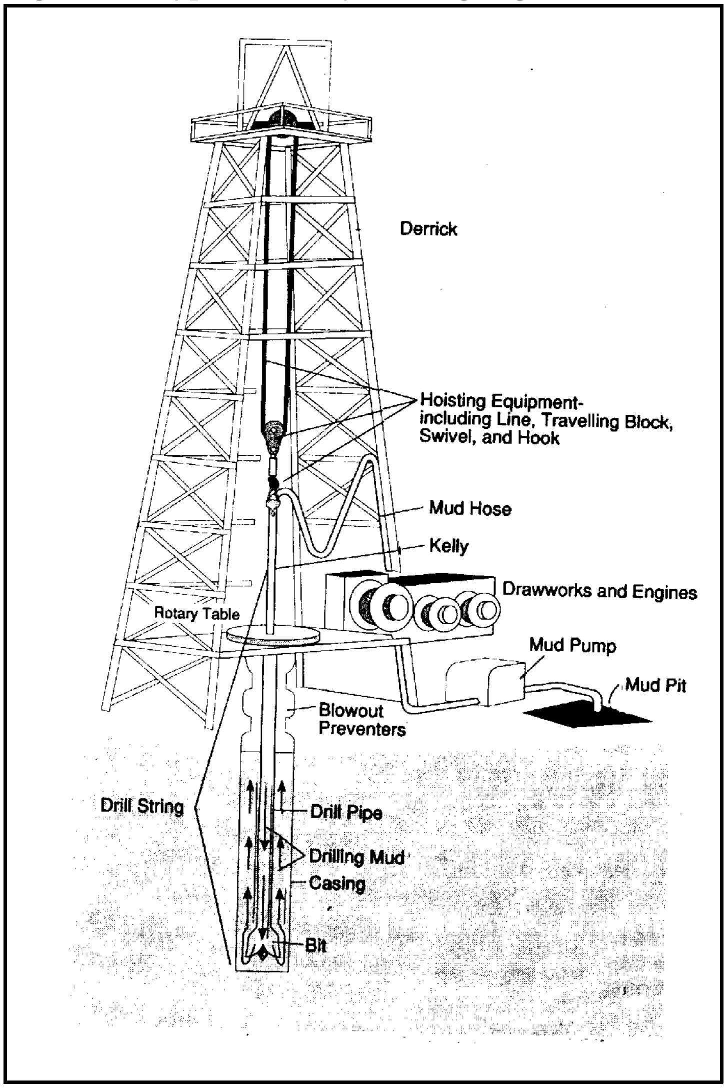
In addition to the well and its accouterments, infrastructure including construction and equipment is necessary at the surface. Roads and a pad are built at onshore sites; a ship, floating structure, or a fixed platform is needed for offshore operations. In addition, devices are needed to lift and lower the drilling equipment, filter rock cuttings from the drilling fluid, and store excess fluid and waste. The following sections describe the equipment required for onshore and offshore sites, respectively.

Onshore Drilling
Because the majority of onshore drilling sites are accessed by road, the equipment is geared toward mobility. First, an access road is built. In many locations the building of an access road is not difficult, but some areas present complications. On the North Slope of Alaska, for example, building a road that does not melt the permafrost can be both challenging and expensive. Board roads are used in some locations where soil conditions are not stable. Next, a footing for the equipment, usually gravel, is created in areas where the

ground may be either unstable or subject to freeze/thaw cycles. Finally, the drilling rig is brought in. For shallow wells, the drill rig may be self-contained on a single truck; for deeper wells, the rig may be brought to the site in several pieces and assembled at the site.

A basic arrangement of the actual drilling equipment, or *rig*, is shown in Figure 11. The derrick (sometimes referred to as the mast) is the centerpiece of the operation, and is the frame from which the drill string is lifted, lowered, and turned. The hoisting equipment, kelly, and drill pipe connect the bit to the derrick. The drawworks and engines next to the derrick lift and drive the drill string, by turning the rotary table. The drilling mud is circulated through the wellbore via the mud hose (also called a gooseneck), down through the rotary hose (not shown), kelly, and drillpipe, out nozzles in the drill bit, and back up to the surface between the drill string and the wellbore. The mud is pumped by the mud pump, and is stored in the mud (or reserve) pit or in mud tanks. Finally, blowout preventers, which are described later in this section, are installed as a safety measure to prevent the drill pipe and subsurface fluids from being blown out of the hole if a high-pressure formation is encountered during drilling. Rigs will often have much more equipment, including a shale shaker which separates rock cuttings, a desander and desilter, which remove smaller particles, and a vacuum degasser, which removes entrained gas (Berger and Anderson, 1992).

Figure 11: Typical Rotary Drilling Rig



Source: Energy Information Administration, Department of Energy, 1991.

Offshore Drilling

For offshore sites, selecting the type of drilling rig needed is very important. Two primary considerations in rig selection are: (1) the size of the rig needed for the depth drilled, and (2) the depth of the water. Exploratory wells (called wildcat wells) may be located far from established oil and natural gas fields, and the rig must be transported over a significant distance. Mobility is therefore a primary concern in these situations. The depth of water at the drilling site is also important. If the water is fairly shallow, a ground-supported rig may be used. If the water is deep (typically over 400 feet), a floating rig may be necessary. The following is a description of the significant offshore rig types:

Drillships are a popular choice for drilling in deep water, because they are the most mobile of the rig types and have a large capacity for drill strings, casing, and similar supplies. A drillship has a standard ship hull, with the derrick extending from its center. The ship is kept in place by anchors or by dynamic positioning, a system in which propellers on each side of the ship are coordinated to keep the ship in the same location despite wind, currents, and the torsion caused by drill activities.

Semi-submersible drilling rigs are another option at deep water sites. The rig is usually a rectangular structure that holds the drilling equipment, with ballast containers underneath. These containers can be filled with air to float the rig when moving it. The rig is held in place by anchors or dynamic positioning. The semi-submersible rig is more stable than a drillship, but it is also more cumbersome to move from site to site.

Jack-up rigs float and are very mobile, but rest on the sea floor when drilling. For this reason, they are used in relatively shallow water (i.e., under 400 feet). The rig is towed into place floating, and legs, previously raised for transportation, are lowered to the ocean bottom so that the rig is raised above the water and supported on the ocean floor. The legs may be raised and lowered independently to compensate for an uneven sea floor. In an alternative footing method, mat support, the legs are attached to a mat on the sea floor; this mat distributes the weight over a larger area and minimizes the risk of the rig sinking into the soft ocean floor.

Fixed structures are commonly used after exploratory or developmental drilling prove a site has economically recoverable hydrocarbons. In these cases, offshore drilling rigs are mounted onto the production platform, which are securely pinned to the sea floor by concrete, steel, or tension legs. Tension legs are hollow steel tendons that allow no vertical movement, but some horizontal movement. They are the largest and most complex offshore structures and can be used in water in depths of over 500 feet (usually less than 1,000 feet). Platforms are very stable and can withstand waves greater than 60 feet high, and winds in excess of 90 knots. Assembling a fixed platform is a sizeable investment; some platforms have been reported to cost over $1 billion (Berger and Anderson, 1992). For this reason, multiple wells are usually drilled at outward angles from a single platform. The centralizing of pumps and separation equipment also make this a convenient arrangement for production (Kennedy, 1983).

Lake and Wetland Drilling

Inland regions of water often require additional engineering techniques and special adaptations other than the onshore and offshore practices mentioned above. In places of deeper and more open water, barge rigs may be used for drilling. In shallow areas or wetlands, stationary rigs can be constructed or the area can be backfilled and drilled with a land-based rig. Canals may also be dredged to bring in floating or submergible drilling rigs. It is common while drilling in wetlands to use the directional drilling technique in order to disrupt as little of the wetland as possible while developing a field. Often supplies and equipment must be transported by helicopter, or dredging is required for access by barge rigs. Regardless of the approach used, these areas often pose challenges for erecting the rig and transporting materials and personnel to and from the site, and involves compliance with Clean Water Act wetlands regulations (See Section VI.B for additional information) (Kennedy, 1983, and EPA, 1995).

Well Completion

When drilling has been completed, several steps may be needed before production begins. First, testing is performed to verify whether the hydrocarbon-bearing formations are capable of producing enough hydrocarbons to warrant well completion and production. As many as three types of tests may be performed before the final (production) string of casing is installed. These tests are coring, wireline logging, and drill stem testing.

Coring is typically performed only in exploratory wells, and not in fields where several wells have already been drilled. A special drill removes an intact sample, or *core*, of rock at the depth where oil or gas is most likely to be. The core can be as short as 15 feet or as long as 90 feet. Special side-wall coring techniques may be employed in some wells. Unlike the more indirect testing methods described below, a core allows a geologist to observe the rock type directly, and measure its *porosity*, or the volume of fluid-occupying space relative to the volume of rock, and *permeability*, the ease with which fluids can flow through a porous rock.

Wireline logging refers to the recording of acoustical, electrical resistivity, and other geophysical measurements within a wellbore. These measurements provide detailed information on the geologic formations encountered by the well, and augment the seismic data recorded prior to the well drilling and the mud log for that well. These data often help to determine more precisely the depth at which oil and gas could be produced. A logging of electrical resistivity takes advantage of the fact that some compounds are better insulators of electrical charge than others. For example, oil, gas, and consolidated rock resist electrical current better than water and unconsolidated rock. Additional tests may be used; radioactivity logs can differentiate between types of rock, and neutron logs can measure the amount of liquid in the formation (but not differentiate between oil and water). Logging is performed on nearly all wells, and multiple forms of logging may be used in conjunction with each other to attain a more complete analysis. For example, a neutron log will indicate the amount of liquid in a formation, and a resistivity log may help to determine what percentage of that liquid is oil. Certain types of logs may be conducted during drilling with a special tool located on the drillstring above the bit.

Drill stem testing may be the most important and definitive test. Equipment attached to the bottom of a drill string traps a sample of formation fluid. Measuring the pressure at which the fluid enters the chamber and the pressure required to expel that fluid back into the formation yields an estimate of the flow rate of formation fluid to be expected during production. If the flow rate is expected to be too low, procedures such as stimulation (see below) may be required to increase the flow before production equipment is installed.

Perforation

When the production casing is cemented in the wellbore, the casing is sealed between the casing and the walls of the well. For formation fluid (oil, gas, and water) to enter the well, the casing must be perforated. The depth of the producing zone is determined by analyzing the logging data; small, directed explosive charges are detonated at this depth, thereby perforating the casing, cement, and formation. The result is that formation fluid enters the well, yet the rest of the well's casing remains intact.

Stimulation

Some formations may have a large amount of oil as indicated by coring and logging, but may have a poor flow rate. This may be because the production zone is not have sufficient permeability, or because the formation was damaged or clogged during drilling operations. In these cases, pores are opened in the formation to allow fluid to flow more easily into the well. The hydraulic fracturing method involves introducing liquid at high pressure into the formation, thereby causing the formation to crack. Sand or a similar porous substance is then emplaced into the cracks to prop the fractures open. Another method, acidizing, involves pumping acid, most frequently hydrochloric acid, to the formation, which dissolves soluble material so that pores open and fluid flows more quickly into the well. Both fracturing and acidizing may be performed simultaneously if desired, in an acid fracture treatment. Stimulation may be performed during well completion, or later during maintenance, or *workover*, operations, if the oil-carrying channels become clogged with time (EPA, 1992).

Production equipment installation

When drilling, casing, and testing operations are completed, the drilling rig is removed and the production rig is installed. In most cases, tubing is installed in the well which carries the liquids and gas to the surface. At the surface, a series of valves, collectively called the Christmas tree because of its appearance, is installed to control the flow of fluid from the well. Pumps are added if the formation pressure is not sufficient to force the formation fluid to the surface. Different types of pumps are available; the most common is the rod pump. The rod pump is suspended on a string of rods from a pumping unit, and the prime mover for pumping units can be an electric motor, or a gas engine. Equipment is usually installed onsite to separate natural gas and liquid phases of the production and remove impurities. Finally, a pipeline connection or storage container (tank) is connected to the well to facilitate transport or store the product. In the case of natural gas, which cannot be stored easily, a pipeline connection is necessary before the well can be placed on production.

Although the practice is becoming less common, one or more pits may be constructed for onshore facilities. These may include a skimming pit, which reclaims residual oil removed with water that has been removed from the product stream; a sediment pit, which stores solids that have settled out in storage tanks; or an evaporation or percolation pit, which disposes of produced water (EPA, 1992).

III.A.3. Petroleum Production

The major activities of petroleum production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities. Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as well as the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Although the following discussion is geared toward wells producing both oil and gas, the majority of the discussion also applies to wells producing exclusively one or the other.

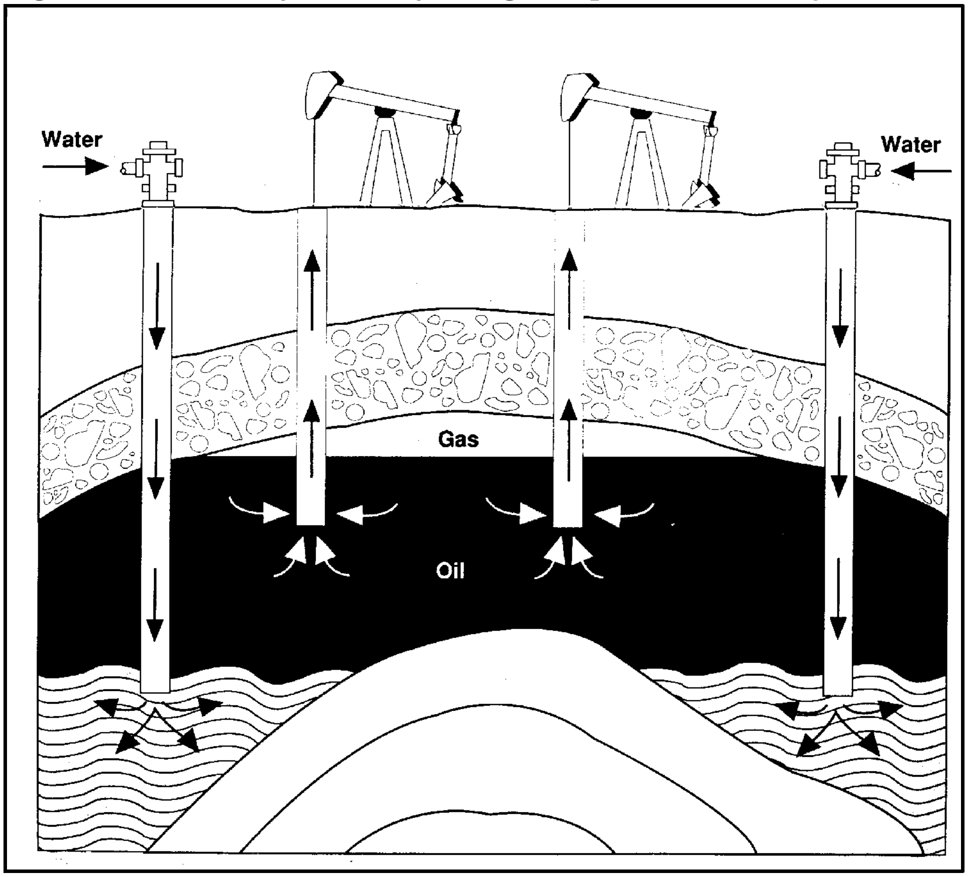
Primary Production

Primary recovery is the first stage of hydrocarbon production, and natural reservoir pressure is often used to recover oil. When natural pressure is not sufficiently capable of forcing oil to the surface, artificial lift equipment is then employed. This includes various types of pumps, gas lift valves, and may occasionally include oil stimulation. When pumping is employed, motors may be used at the surface or inside the wellbore to assist in lifting the fluid to the surface. Primary production accounts for less than 25 percent of the original oil in place.

Secondary Recovery

Secondary recovery enhances the recovery of liquid hydrocarbons by repressurizing the reservoir and reestablishing or supporting the natural water drive. Usually water which is produced with the oil is reinjected, but other sources of water may also be used. This type of secondary recovery is generally called a "waterflood" (See Figure 12). Produced water injection for enhanced recovery of crude oil and natural gas is recognized as a form of recycling of this waste. Furthermore, produced water is more commonly injected for the purpose of secondary recovery than in an injection well that is only used for disposal (in Texas, approximately 61 percent of injected produced water is for enhanced recovery) (Texas Railroad Commission, 1999). This procedure is described further in Section III.C., Management of Wastestreams. Gas is injected to enhance gas cap drive in some reservoirs.

Figure 12: Secondary Recovery Using Pumps and Water Injection



Source: Energy Information Administration, Department of Energy, 1991.

Tertiary Recovery

A final method for removing the last extractable oil and gas is tertiary recovery. In contrast to primary and secondary recovery techniques, tertiary recovery involves the addition of materials not normally found in the reservoir (Lake, 1989). These methods are often expensive and energy-intensive (Sittig, 1978). In most cases, a substance is injected into the reservoir, mobilizes the oil or gas, and is removed with the product. Examples include:

- Thermal recovery, in which the reservoir fluid is heated either with the injection of steam or by controlled burning in the reservoir, which makes the fluid less viscous and more conducive to flow;
- Miscible injection, in which an oil-miscible fluid, such as carbon dioxide or an alcohol, is injected to reduce the oil density and cause it to rise to the surface more easily;
- Surfactants, which essentially wash the oil from the reservoir; and
- Microbial enhanced recovery, in which special organic-digesting microbes are injected along with oxygen into the formation to digest heavy oil and asphalt, thereby allowing lighter oil to flow (Lake, 1989; EPA, 1992)

Crude Oil Separation

When the formation fluid is brought to the surface, it may contain a spectrum of substances including natural gas, water, sand, silt, and any additives used to enhance extraction. The general order of separation with respect to oil is the following: the separation of gaseous components, the removal of solids and water, and the breaking up of oil-water emulsions. (The conditioning of the natural gas that is removed in the first step will be discussed in the next subsection.)

The removal of gaseous components primarily is intended to remove natural gas from the liquid; however, gaseous contaminants such as hydrogen sulfide (H_2S) also may be produced in some fields during this process. The gases are removed by passing the pressurized fluid through one or two decreasing pressure chambers; less and less gas will remain dissolved in the solution as the pressure is lowered.

The liquids and solids that remain are usually a complex mix of water, oil, and sand. Water and oil are generally immiscible; however, the extraction process is usually very turbulent and may cause the water and oil to form an emulsion, in which the oil forms tiny droplets in the water (or vice versa). Fluid separation often produces a layer of sand, a layer of relatively oil-free water, a layer of emulsion, and a (small) layer of relatively pure oil. The free water and sand, or basic sediment and water (BS&W) are generally removed by a process called free water knockout, in which the BS&W are removed primarily by gravity. Finally, emulsions are broken by heating the fluid in a heater-treater to a temperature of 100-160 degrees fahrenheit, or by treating it with emulsion-breaking chemicals (Arnold and Stewart, 1998). Following the emulsion breaking, the oil is about 98 percent pure, which is sufficient for storage or transportation to the refinery (Sittig, 1978).

Natural Gas Conditioning

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of high enough quality to pass through transportation systems. It should be noted that conditioning is not always required; natural gas from some formations emerges from the well sufficiently pure that it can pass directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or problems. The most significant is hydrogen sulfide (H_2S), which may or may not be contained in natural gas. Hydrogen sulfide is toxic (and potentially fatal at certain concentrations) to humans and corrosive for pipes; it is therefore desirable to remove it as soon as possible in the conditioning process. Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas (methane) in the subsurface. These other gases must be separated from the methane prior to sale. At cold temperatures the water can freeze, also clogging pipes, valves, and gauges. High vapor pressure hydrocarbons that are found to be liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately. Two significant natural gas conditioning processes are dehydration and sweetening.

Dehydration is performed to remove water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration, and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing occurs in the field (at or near the well). At natural gas plants, solid desiccants are most commonly used (Smith, 1999).

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product. Another method of sweetening involves the use of iron sponge, which reacts with H_2S to form iron sulfide and later is oxidized, then buried or incinerated (EPA, 1992).

III.A.4. Maintenance

Production wells periodically require significant maintenance sessions, called *workovers*. During a workover, several tasks may be undertaken: repairing leaks in the casing or tubing, replacing motors or other downhole equipment, stimulating the well, perforating a different section of casing to produce from a different formation in the well, and painting and cleaning the equipment. The procedure often requires bringing in a rig for the downhole work. This rig can be smaller than those used for initially drilling a well.

Two procedures performed to improve the flow of fluid during workovers are removing accumulated salts (called *scale*) and paraffin, and treating production tubing, gathering lines, and valves for corrosion with corrosion-prevention compounds. As fluids are withdrawn from the formation, the salts that are dissolved in the produced water precipitate out of solution as the solution approaches the surface and cools. The resulting scale buildup can significantly reduce the flow of fluid through the tubing, gathering lines, and valves. Examples of scale removal chemicals are hydrochloric and hydrofluoric acids, organic acids, and phosphates (EPA, 1994). These solvents are added to the bottom of the wellbore and pumped through the tubing through which extracted fluid passes. In a similar fashion, corrosion inhibitors may be passed through the system to mitigate and prevent the effects of acidic components of the formation fluid, such as H_2S and CO_2. These corrosion inhibitors, such as ammonium bisulfite or several forms of zinc, may serve to neutralize acid or form a corrosion-resistant coating along the production tubing and gathering lines. Corrosion control activities can be continuous, not just at workover.

III.A.5. Well Shut-in/Well Abandonment

Production may be stopped for several reasons. If it is a temporary stoppage, the well is shut-in. If the closure is to be permanent, the well is either converted to a UIC Class II injection well, or it is plugged and abandoned.

A temporary shut-in is an option when the conditions causing the interruption in production are anticipated to be short-term. Examples include situations when the well may be awaiting a workover crew or a connection to a pipeline, or there may be a (temporary) lack of a market (Williams and Meyers, 1997). A well is shut in by closing the valves on the Christmas tree. Depending on the duration, the stoppage may be called a temporary abandonment, and regulatory approval and testing, including a mechanical integrity test (MIT), may be required in order to be idle (IOGCC, 1996). It is much more desirable to shut-in a well rather than plug it if production is still viable, because once the well is permanently plugged and abandoned, it is highly impractical to re-access the remaining oil in the reservoir.

If the well is part of a production field with many nearby wells still in production, the well may be converted to a UIC Class II injection well, which is regulated under the Safe Drinking Water Act (see Section VI.B, Sector-Specific Requirements for more information). Such a well can be used either for disposal of the produced water from these other wells, or may be part of a coordinated Enhanced Oil Recovery (EOR) effort in the field.

The final option is to plug and abandon the well. The goal of this procedure is to prevent fluid migration within the wellbore, which could contaminate aquifers or surface water. Oil and gas producing states all have specific regulations governing the plugging and abandonment of wells (see Section VI.B.4., State Regulations). When a well is plugged, the downhole equipment is removed and the perforated parts of the wellbore are cleaned of fill, scale and other debris. A minimum of three cement plugs are then placed, each of which are 100 to 200 feet long. The first is pumped into the perforated (production) zone of the well, in order to prevent the inflow of fluid. A second is placed in the middle of the wellbore. A third plug is placed within a couple hundred feet of the surface. Additional plugs may be placed anywhere within the wellbore when necessary. Fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure. During this process, the plugs are tested to verify plug placement and integrity (Fields and Martin, 1998). Finally, the casing is cut off below the surface, capped with a steel plate welded to the casing, and at onshore sites, surface reclamation is undertaken to restore natural soil consistency and plant cover (EPA, 1992).

Problems are sometimes encountered with wells that have stopped production, yet neither have government approval nor have been plugged. These are generally called idle wells, or when the owners are not known or are insolvent, are called orphan wells. Please see Section III.B for the possible environmental impacts of such wells.

Offshore Platform Decommissioning

For offshore, the structure itself must be decommissioned in addition to plugging the well. Several options exist:

- Complete removal of the structure and disposing of the structure onshore
- Removing the structure and placing it in an approved location in the ocean
- Reuse of the structure elsewhere (National Research Council, 1996).

The method used will vary with the type of structure and water depth, but the most common approach is the complete removal of the structure, with removal at a minimum of 15 feet below the mudline (seafloor). Other approaches are less expensive and less intrusive to the existing environment, but can be more dangerous for commercial ships, military submarines, fishing trawlers, and recreational boaters. In Texas and Louisiana, however, it may be possible to participate in the states' "rigs-to-reefs" programs, which under the National Fishing Enhancement Act of 1984 seek to convert offshore structures to permanent artificial reefs (MMS, 1999).

When removing the structure, the most common approach is to sever the leg piles with explosives. Explosives must be placed at least five feet below the mud line (sea floor). Explosives are less expensive and are less risky to divers than alternatives such as manual or mechanical cutting, but concern has been raised about the use of explosives and their effect on marine life (National Research Council, 1996).

III.A.6. Spill and Blowout Mitigation

Accidental releases at oil and gas production facilities may come in two forms: spills or blowouts. Oil spills (usually consisting of crude oil or condensate) may come from several sources at production sites (and in some cases at drilling sites): leaking tanks, during transfers, or from leaking flowlines, valves, joints, or gauges. Other spills of oil have occurred such as diesel from drilling operations, oily drilling muds while being offloaded, and production chemicals (MMS, 1998). Spills are the most common type of accident and are often small in quantity.

Well blowouts are rare, but can be quite serious. They are most likely to occur during drilling and workovers, but can occur during any phase of well development including production operations. When the drill encounters an unusually pressurized zone or when equipment is being removed from the hole, the pressure exerted by the formation may become considerably higher than that exerted by the drilling or workover fluid. When this happens, the formation fluid and drilling or workover fluid may rise uncontrollably through the well to the surface. Downhole equipment may also be thrust to the surface. Especially if there is a significant quantity of associated natural gas, the fluid may ignite from an engine spark or other source of flame. Blowouts have been known to completely destroy rigs and kill nearby workers. Some blowouts can be controlled in a matter of days, but some -- particularly offshore -- may take months to cap and control (Kennedy, 1983).

Drilled wells and many workover wells are equipped with a blowout preventer. These blowout preventers (BOPs) are hydraulically operated, and serve to close off the drill pipe. BOPs can be operated manually, or can be automatically triggered. Most rigs have regular blowout drills and training sessions so that workers can operate the BOPs and escape as safely as possible.

Should a spill occur despite precautions, established responses should be undertaken. If the facility is subject to Spill Prevention Control and Countermeasure (SPCC) regulation (see Section VI.B for additional information), the facility will be equipped with secondary containment and diversionary structures to prevent the spill from reaching drains, ditches, rivers, and navigable waters. These structures may be berms, retention ponds, absorbent material, weirs, booms, or other barriers or equivalent preventive systems. Should these secondary containment devices not be adequate, the response will be different for onshore and offshore spills (EPA, 1999). In both cases, the goals are to stop the flow of oil, recover as much as possible of the material as a salable product, then minimize the impact on navigable waterways or groundwater.

<u>Onshore Spills</u>

For onshore spills, concern is for both surface runoff to streams, and for seepage into groundwater. The first considerations are to stop the source of the leakage and to contain the spill. Containment may either be achieved with pre-existing structures, or by using bulldozers at the time of response (Blaikley, 1979). Pooled oil would then be collected, pumped out, and whenever possible, processed for sale. When treating the contaminated soil, the remediation approach taken may vary considerably depending on the porosity of the soil and composition of the spilled fluid. If the spill has permeated less than about 6-10 inches of soil, bioremediation may be the most appropriate approach. With bioremediation, hydrocarbon-digesting microbes found naturally in soil are enhanced with fertilizers and moisture to degrade the material. The site would be tilled periodically and watered to maintain proper amounts of air and moisture. Should the temperature at the site be too cold or should the spill be too deep for bioremediation to be fully effective, approaches such as composting, or soil excavation with landspreading or landfilling, may be used either exclusively or in combination (Deuel and Holliday, 1997). Another option in remote locations or in situations when other options have not been successful is in-situ burning. In these situations, primarily when there is little surrounding vegetation, calm winds, and difficulty in transporting the equipment required for other methods, the oil is concentrated as much as possible and ignited by any of a variety of methods (Zengel, et al., 1998; Fingas, 1998). Application of in situ burning is still being refined.

Offshore Spills

The conditions for an offshore spill cleanup can vary substantially; from deep-water to coastal, from calm water to very choppy seas. As with onshore spills, initial priorities are to contain spilled oil and prevent further leakage. The oil is usually contained by booms, or floating devices that block the movement of surface oil. The booms may then be moved to concentrate the oil, at which point skimmers collect the oil. Booms may also be placed along a shoreline to minimize the amount of oil that reaches shore. For the oil that cannot be collected in this fashion, other approaches are used to minimize environmental impact, including sorbents, dispersants, or oil-digesting bacteria (EPA, 1993). In-situ burning also may be an option for offshore spills. This option may be best suited to arctic conditions, where cold temperatures keep the oil relatively concentrated and where ice may hinder the use of other methods. Depending on the thickness of the oil, the calmness of the seas, and other factors, the destruction rate can be over 90 percent (Fingas, 1998; Buist, 1998). This technique has not been widely used and is still considered experimental.

III.B. Raw Material Inputs and Pollution Outputs

This section describes the impacts that individual steps in the extraction process may have on adding contaminants to the environment. Relevant inputs and significant output wastes are presented, with outputs summarized in Table 2. The management techniques used to handle the wastes are discussed in Section III.C, and more information on the magnitude and qualities of the releases are found in Section IV.

Oil and gas extraction generates a substantial volume of byproducts and wastes that must be managed. Relatively small volumes of chemicals may be used as additives to facilitate drilling and alter the characteristics of the hydrocarbon flow. For example, acids may be used to increase rock permeability, or biocides may be added to wells to prevent the growth of harmful bacteria. The industry also contends with many naturally occurring chemical substances. Byproducts and wastes result from the separation of impurities found in the extracted hydrocarbons or from accidents when oil is spilled. In addition, most processes involving machinery will produce relatively small quantities of waste lubricating oils and emissions from fossil fuel combustion, and inhabited facilities will produce sanitary wastes. Finally, formation oil contamination may be present in the spent drilling fluids and cuttings.

Drilling

There are a number of possible environmental impacts from the wastes generated during the well drilling and completion/stimulation processes. In the drilling process, rock fragments (cuttings) are brought to the surface in the drilling fluid. These cuttings pose a problem both in the large volume produced and the muds that coat the cuttings as they are extracted. Oil-based fluids have the added stigma of having oil frequently coating the cuttings. The volume of rock cuttings produced from drilling is primarily a function of the depth of the well and the diameter of the wellbore. It has been estimated that between 0.2 barrels and 2.0 barrels (8.4 and 84.0 gallons) of total drilling waste are produced for each vertical foot drilled (EPA, 1987).

Drilling mud disposal generally becomes an issue at the end of the drilling process. However, sometimes drilling mud is disposed of during the drilling process when the mud viscosity or density needs to be changed to meet the demands of formation pressures. This can create special concerns for offshore operations where the disposal of a large volume of mud over a short period can create a mud blanket on the seafloor that can have an impact on benthic organisms. Industry is limited to using barite stock for the making of drilling mud, which passes 40 CFR 435 requirements (less than or equal to 1 ug/kg dry weight maximum mercury and 3 mg/kg dry weight maximum cadmium).

The muds are combined, however, with dissolved and suspended contaminants including mercury, cadmium, arsenic and hydrocarbons (typically found in trace amounts). The additives listed in Section III.A may be found in waste mud, and components from the formation, such as hydrogen sulfide and natural gas, may also be dissolved in the mud. Rock cuttings from the formations overlying the target formation may contribute contaminants to the drilling mud such as arsenic or metals. Also rock cuttings create a large volume of waste and for water-based fluids the rock cuttings may be discharged to surface waters offshore. Oil-based mud will also contain diesel oil that must be disposed of properly, or more typically, conditioned for reuse. Oil-based muds and cuttings cannot be discharged to surface waters. Both oil-based and synthetic-based fluid are conditioned and reused, which reduces waste volume from drilling operations.

Drilling operations also produce air emissions, such as exhaust from diesel engines and turbines that power the drilling equipment. The air pollutants from these devices will be those traditionally associated with combustion sources, including nitrogen oxides, particulates, ozone, and carbon monoxide. Additionally, hydrogen sulfide may be released during the drilling process (EPA, 1992).

Some steps in the well completion process may produce waste. The most prominent is stimulation. Unused hydrochloric acid must be neutralized if acid stimulation is being used, and paraffins and any other dissolved materials brought to the surface from the formation must be disposed of as well. In addition, solid wastes such as waste cement and metal casing may remain from the casing process.

Production

The primary byproduct from the production process (and the dominant one on a volume basis in the industry) is produced water. Other wastes that may be generated during production include the residual wastes that remain after separation of the oil and natural gas.

<u>Produced Water</u>

The largest volume byproduct by far in the extraction process is water extracted with oil. In wells nearing the end of their productive lives, water can comprise 98 percent of the material brought to the surface (Wiedeman, 1996). The American Petroleum Institute estimates that over 15 billion barrels of water are produced annually. This is nearly eight barrels of water for every barrel of oil produced. Natural gas wells typically produce much lower volumes of water than oil wells, with the exception of certain types of gas resources such as coalbed methane or Devonian/Antrim shales (API, 1997).

Although many petroleum components are separated from the water easily, some components and impurities are water-soluble and difficult to remove. Some substances may be found in high concentrations, including chloride, sodium, calcium, magnesium and potassium. Others found are:

- Organic compounds: benzene, naphthalene, toluene, phenanthrene, bromodichloromethane, and pentachlorophenol;
- Inorganics: lead, arsenic, barium, antimony, sulfur, and zinc;
- Radionuclides: uranium, radon, and radium (EPA, 1992).

It should be noted that concentrations of these pollutants will vary considerably depending on the location of the well and the extent of treatment of the water. Geography can be a key factor in whether a substance may exist in produced water. For example, radionuclides are found only in some areas of the country.

The risks of water pollution due to produced water management differ for onshore and offshore operations, and are discussed separately.

Onshore operations, and coastal and shallow offshore areas, may pose a risk to the environment if produced water with high saline concentrations is not properly managed. The saline concentration of produced water varies widely. In some locations, the produced water can have salt concentrations of 200,000 mg/L (Stephenson, 1992). However, in some areas west of the 98th Meridian, produced water may contain low enough levels of salt that it may be used (upon meeting regulatory limits for oil and grease) for beneficial use for irrigation or livestock watering (EPA, 1992; Railroad Commission of Texas, 1999).

The discharge of produced water inappropriately onto soil can result in salinity levels too high to sustain plant growth. If introduced to a water supply, the water can be unusable for human consumption. The introduction of metals and organic compounds from produced water are also a concern. (See Section IV for more details on contaminants in produced water.) However, over 90 percent of onshore produced water is injected for enhanced recovery or disposal (Smith, 1999). This injection involves a closed system from the producing wellbore to the injection wellbore, so the potential for release to the soil is minimized.

Offshore operations may impact the area immediately surrounding the platform if produced water effluents are not properly treated and discharged. The concentration of metals, radionuclides, residual oily materials and high BOD in the produced water may be higher than the surrounding water. However, the impact is reduced significantly at greater distances from the well; research in the Gulf of Mexico has indicated that produced water can be diluted 100-fold within 100 meters of the discharge (Neff and Sauer, 1996).

Natural Gas Processing

Wastes are generated when natural gas undergoes dehydration and sweetening. For dehydration, triethylene glycol is the most common desiccant. Although glycol is reused, it becomes less effective over time and must be replaced periodically. Glycols are volatile and can be hazardous if inhaled as a vapor. At larger natural gas processing plants, the solid molecular sieves that are used also require periodic replacement.

The wastes from gas sweetening will vary depending on the method used. Possible wastes include spent amine solution, iron sponge, and elemental sulfur. When there is a market for sulfur, it is sold.

Air Emissions

There are several sources of air emissions in the production process. Leaking tubing, valves, tanks, or open pits will release volatile organic compounds (VOCs). When natural gas produced from the well is not sold or used on-site, it is usually flared, thereby releasing carbon monoxide, nitrogen oxides, and possible sulfur dioxide if the gas is sour (see Section III.C. for more information on flaring). Finally, production involves the use of machinery including pumps, heater-treaters, and motors which require fuel combustion. Emissions from these include nitrogen oxides, sulfur oxides, ozone, carbon monoxide, and particulates (EPA, 1992). Where electricity is available, electric-powered equipment may be used. Emissions from natural gas processing plants (SIC 1321) are larger than field production operations due to the greater scale and concentration of equipment. Even at gas plants most engines are powered by natural gas or electricity.

Other Wastes

The sand that is separated from produced water must be disposed of properly. Similar to the sand removed during the drilling process, this sand is often contaminated with oil and trace amounts of metals or other naturally occurring constituents.

Most oil and gas operations include tanks for the temporary storage of oil, natural gas liquids, and/or produced water. While stored, small solid particles that were entrained in the liquids can settle out, forming a sludge on the bottom of the tank. These “tank bottoms,” or “basic sediment and water” (BS&W) wastes, may be periodically removed from the tank and disposed of. Some tanks may require cleaning a few times per year; others may require cleaning once every 10 years. The need for tank cleaning, and therefore the generation of these wastes, is dependent upon the characteristics of the fluids being handled and the operation. Because they are removed from hydrocarbon storage tanks, tank bottoms are likely to contain oil and smaller amounts of other constituents (see Section IV for an example of concentrations of contaminants in these sediments.)

Maintenance

The workover process requires many of the same inputs and produces similar outputs as the drilling process. In particular, workover fluid, which is similar to drilling fluid, is required to control downhole pressure. Also, emissions will result from the combustion of fuels to power the rig.

Workovers also use additional inputs and produce other pollutants, some of which are toxic. The compounds usually appear in the produced water when production resumes, or in the case of cleaning fluids, may be spilled from equipment at the surface.

Scale removal requires strong acids, such as hydrochloric or hydrofluoric acids. When carried to the surface in produced water, any acids not neutralized during use must be neutralized before being disposed, usually in a Class II injection well. Scale is primarily comprised of sodium, calcium, chloride and carbonate; however, trace contaminants such as barium, strontium, and radium may be present.

Also, corrosion inhibitors and stimulation compounds are flushed through the well. Corrosion-resistant compounds of concern include zinc carbonate and aluminum bisulfate. Stimulation may require acidic fluids.

In addition, painting- and cleaning-related wastes may be generated during workovers. Paint fumes and cleaning solvent vapor may produce gaseous emissions, paint and cleaning solvents with suspended oil and grease must be disposed of properly, and paint containers will require disposal as a solid.

Collectively, wastes produced by the industry other than drilling wastes and produced water are called associated wastes. The volume is usually small, about one barrel per well per year (DOE, 1993). Because associated wastes are those associated with chemical treatment or wells or produced fluids, post-treatment materials, and residual waste streams, they are more likely to have higher hydrocarbon or chemical constituent content than produced water or waste drilling fluids.

In 1985, API estimated that approximately 12 billion barrels of associated wastes were generated annually (Wakim, 1987). API estimates that in 1995, the annual volume of associated wastes is 22 millions barrels (API, 1997). The higher volume is attributed primarily to a difference in definitions between the two studies (i.e., the 1995 study includes wastes form gas plants that were not included in 1985). On a comparable basis, there has been only a slight increase in associated waste volumes over the past decade. This increase can be attributed primarily to aging wells requiring more stimulation or workover treatments to remain on production. Table 1 summarizes the types of associated wastes and their relative volume based on a 1985 API industry survey.

Table 1: Types of Associated Waste

Material	Process	Percent of Total Associated Waste Volume
Workover wastes (mud and other completion fluids, oil, chemicals, acid water, cement, sand)	Maintenance	34%
Produced sand, separator sludges	Production	21%
Other production fluid waste	Production	14%
Oily debris, filters, contaminated soils	All	12%
Cooling water, engine and other waste water	All	8%
Dehydration and sweetening unit wastes	Production	4%
Untreatable emulsions	Production	2%
Used solvents and cleaners	Maintenance	2%
Other production solid waste	Production	1%
Used lubricating or hydraulic oils	All	1%

Source: U.S. Department of Energy, 1993. (Based on a 1985 API survey)

Idle/Orphan Wells

Idle wells are wells that have ceased production (either temporarily or permanently) but have not been plugged. Generally the state regulatory agency knows the operator who is responsible for these wells, and in most states, wells require regulatory approval to be idle. However, a small percentage of these are orphan wells, for which no responsible party exists. This may be because the operator is unknown (in the case of wells drilled in the early part of the century) or because the operator has gone bankrupt and has no assets available.

Wells that have stopped production yet neither have state government approval nor have been plugged are uncommon. Approximately 134,000 of the nearly 2.7 million total wells drilled by 1995 in the United States are in this category (IOGCC, 1996). These wells may pose problems with respect to migrating reservoir fluid. With these wells, the mechanical integrity of the casing is not known, and therefore it may be possible for reservoir fluid to migrate to fresh water aquifers. In such cases, the primary contaminant would be saline formation water that could pollute fresh water aquifers and possibly surface waters.

It should be noted that not all of these wells will necessarily cause pollution; rather, the concern is that the risk posed by these wells is variable. Currently, most oil- and gas-producing states are handling the issue by prioritizing among these wells, and have established programs to plug dangerous orphan wells and clean up any contamination that may have already occurred. One way in which this prioritization is achieved is through area of review (AOR) studies that are required for the approval of new UIC wells. Under this requirement, the operator of the new well must study all active, idle and abandoned wells within an area (often a 1/4 mile radius) to determine whether they pose a risk of contamination (IOGCC, 1996).

Spills and Blowouts

Based on data from the U.S. Coast Guard and other sources, the American Petroleum Institute reported that in 1996, 1,276 onshore facilities reported spills of crude oil for a total of 131,000 gallons. This total would include spills from field operations, but also would include spills of crude oil at refineries, terminals, and other types of facilities. Spill volumes specifically for crude oil are not available. According to the Coast Guard, 78 percent of spills in 1996 were less than 10 gallons (API, 1998b).

Production facilities often have systems in place for handling larger accidents such as blowouts, and many onshore oil and gas operations must have a Spill Prevention Control and Countermeasures (SPCC) Plan in place for addressing spills. Under the CWA only spills above a certain threshold must be reported (see Section IV for more details on SPCC and CWA regulations). However, smaller spills appear to account for most reported crude oil releases. These are most likely to occur due to poor connections in filling or removing materials from tanks (Smith, 1999).

Offshore, the Marine Minerals Service collects data on oil spills. According to MMS, in 1995 there were 34 spills from production operations in the Gulf of Mexico, totaling 773 barrels. There was also one spill of one barrel of oil on the Pacific Coast (MMS, 1995).

In addition to oil spills, well blowouts can result in accidental releases of material. In a blowout, the pollutant can be produced water and oil, or drilling fluids and workover fluids, such that possible components of concern are salt, heavy metals, and oil. The produced water and oil mixture can be spread in a wide area around the rig possibly leaching through the soil to a fresh water aquifer or running off into nearby surface waters. Onshore, statistics on the number of blowouts annually are not available. Offshore, according to data from MMS, there was only one blowout in 1995, and 15 blowouts between 1991 and 1995. The total amount of oil spilled as a result of those blowouts was 100 barrels, all in 1992. It is assumed from the historical distribution that 14 percent of all blowouts could result in the spillage of crude oil or condensate, with 4 percent of the blowouts resulting in spills greater than 50 barrels. Since 1992, all blowouts have been controlled without any spills (MMS, 1995).

Accidental releases can also include air emissions. Crude oil contains organic compounds that may volatilize and be emitted before the spill can be cleaned up. In-situ burning of crude oil is one approach for cleaning up spills. Use of burning can result in emissions from the combustion, including particulates and carbon monoxide. Blowouts can result in the emission of methane (natural gas). If the well ignites, combustion outputs would be expected. In rare cases, process upsets at facilities that process sour natural gas could result in the release of hydrogen sulfide.

Table 2: Potential Material Outputs from Selected Oil and Gas Extraction Processes

Process	Air Emissions	Process Waste Water	Residual Wastes Generated
Well Development	fugitive natural gas, other volatile organic compounds (VOCs), Polyaromatic hydrocarbons (PAHs), carbon dioxide, carbon monoxide, hydrogen sulfide	drilling muds, organic acids, alkalis, diesel oil, crankcase oils, acidic stimulation fluids (hydrochloric and hydrofluoric acids)	drill cuttings (some oil-coated), drilling mud solids, weighting agents, dispersants, corrosion inhibitors, surfactants, flocculating agents, concrete, casing, paraffins
Production	fugitive natural gas, other VOCs, PAHs, carbon dioxide, carbon monoxide, hydrogen sulfide, fugitive BTEX (benzene, toluene, ethylbenzene, and xylene) from natural gas conditioning	produced water possibly containing heavy metals, radionuclides, dissolved solids, oxygen-demanding organic compounds, and high levels of salts. also may contain additives including biocides, lubricants, corrosion inhibitors. wastewater containing glycol, amines, salts, and untreatable emulsions	produced sand, elemental sulfur, spent catalysts, separator sludge, tank bottoms, used filters, sanitary wastes
Maintenance	volatile cleaning agents, paints, other VOCs, hydrochloric acid gas	completion fluid, wastewater containing well-cleaning solvents (detergents and degreasers), paint, stimulation agents	pipe scale, waste paints, paraffins, cement, sand
Abandoned Wells, Spills and Blowouts	fugitive natural gas and other VOCs, PAHs, particulate matter, sulfur compounds, carbon dioxide, carbon monoxide	escaping oil and brine	contaminated soils, sorbents

Sources: Sittig, 1978, EPA Office of Solid Waste, 1987.

III.C. Management of Wastestreams

The primary wastestreams are those associated with drilling wastes and produced water. As a result, most disposal options are oriented toward these two waste categories. The management of associated wastes and of gases is also briefly described.

Liquids

Underground Injection

Underground injection is the most common disposal method of produced water; over 90 percent of onshore produced water is disposed of through injection wells (API, 1997), but it is rare at offshore facilities. For disposal of produced water by underground injection, two options are available: to inject the water as a waste disposal method, or to use the produced water as part of a waterflooding effort for enhanced recovery. Water being disposed of typically is injected into known formations, such as a former producing formation. In a few Appalachian states, annular injection of produced water may be used, in which case the fluid is pumped into the space between tubing and casing (or uncased formation) within the well (EPA, 1992).

The second option, implemented especially in locations where formation pressure may be relatively low, is reinjecting produced water into the oil- and gas-producing formation. (See Figure 12 on page 29 for an illustration.) The volume of produced water used for enhanced recovery is approximately 57 percent of total produced water volumes (API, 1997). This method increases pressure in the formation to force oil toward the well and contributes to secondary recovery efforts. It requires that water be more thoroughly treated before injection; the water should be free of solids, bacteria, and oxygen, all of which could potentially contaminate the oil reservoir and, in the case of sulfur-reducing bacteria, could lead to increased hydrogen sulfide concentrations in the extracted oil. Please see Section VI.B, Sector-Specific Requirements for UIC regulations that apply to produced water underground injection.

Liquid wastes bought onshore may include produced water that fails NPDES toxicity requirements; water extracted from sludge; or treatment, workover, and completion fluids. At commercial waste treatment facilities liquid wastes are usually injected into disposal wells. As of February 1997, there are 94 disposal wells located in the Texas coastal zone and 17 in the Louisiana coastal zone. These wells could be used for disposal of OCS-generated liquid wastes (MMS, 1998).

Roadspreading

If the fluid has the characteristics of materials used for dust suppressants, road oils, deicing materials, or road compaction, the fluid may be used for roadspreading. In this procedure, water is applied to roads at approved rates, in order to prevent pooling or runoff and to minimize the risk of surface water or groundwater contamination. This practice may be subject to testing to ensure that the fluid is similar to the conventional road materials mentioned above, and also to ensure that the level of radioactive material is not above regulatory action levels (IOGCC, 1994). Roadspreading is declining as a disposal option, and accounts for less than 1 percent of produced water volumes (API, 1997).

Use of Produced Water for Irrigation

In areas west of the 98th meridian, produced water from onshore wells that are in the Agricultural and Wildlife Beneficial Use Subcategory may be used as a beneficial use with agriculture. In these cases, treated water that meets water quality standards may be released directly to agricultural canals for use in irrigation or livestock watering (EPA, 1992; Texas Railroad Commission, 1999). Beneficial use of produced water currently accounts for around 4 percent of onshore produced water volumes in the United States (API, 1997).

Evaporation or Percolation Pits

In this approach, produced water is placed in the pit and allowed to either evaporate to the air or percolate into the surrounding soil. These pits can only be used when the fluid will not adversely impact groundwater or surface water, and restrictions may be imposed on water salinity, hydrocarbon content, pH, and radionuclide content. This approach is declining because of potential environmental contamination of groundwater and the potential hazard posed to birds and waterfowl by residual oil in these open pits (IOGCC, 1994; Buckner, 1998). About 2 percent of produced water is currently disposed of using evaporation or percolation pits (API, 1997). Most of this volume is disposed of in percolation pits in arid portions of California.

Treat and Discharge

For this disposal method the water must meet standards for oil and grease content and pass a toxicity test prior to discharge. In 1997, 1 percent of onshore produced water was disposed of in this manner (API, 1997). Until recently, this method was also used at coastal facilities, but has been largely phased out since 1995. The only coastal area where discharge of produced water is currently allowed is Cook Inlet, Alaska.

Treatment and discharge is the primary method for disposing of produced water at offshore operations. Produced water discharges are not expected to take place at every platform or well. The trend in the Gulf of Mexico is for water treatment and separation of the well stream to occur only at designated locations. An industry survey of 1992 discharge monitoring reports submitted annually to USEPA (Shell Oil Company, 1994) found that only 29 percent of existing platforms contain water treatment systems and discharge their produced waters. As industry uses more sophisticated methods of developing shallow oil and gas fields and is required to conduct more complex treatment protocols, it is likely that operators will increasingly use central processing facilities (MMS, 1998).

Industry's projections (Deepstar, 1994) for deepwater are that the oil and gas produced in deepwater will most likely be piped from subsea completions through mixed line pipelines to large processing facilities primarily operating at the shelf break. These processing facilities will separate and process the production streams into oil, gas and water, and then discharge the treated water. The exception to this process would be whenever a floating production, storage and offloading system (FPSO) is chosen as the surface facility receiving oil and gas from subsea completions. An FPSO is a converted tanker used for a production and storage base, usually at a deepwater (greater than 400 meters) production site. These FPSO's, able to operate at any depth, would process the well stream prior to the transport of the products to shallower locations (MMS, 1998).

Table 3: Summary of 1995 Disposal Practices for Onshore Produced Water

Method	Percent of Onshore Produced Water
Injected for Enhanced Recovery	57%
Injection for Disposal	36%
Beneficial Use	4%
Evaporation and Percolation Ponds	2%
Treat and Discharge	1%
Roadspreading	<1%

Source: API, 1997.

Solids

The primary solid waste-generating process is drilling, and therefore the solid waste disposal processes are geared toward drilling waste. However, solid waste is also generated during production and maintenance. Production and maintenance wastes are usually transported offsite. Offshore, solids are often treated and discharged in accordance with Clean Water Act regulations.

In the Gulf of Mexico, offshore oil field wastes that are not discharged or disposed of onsite are brought onshore for disposal and taken to specifically designated commercial oil field waste disposal facilities. In Texas there are ten existing commercial oil field waste disposal facilities that receive all of the types of wastes that would come from the OCS operations (4 stationary treatment, 5 landfarms, and 1 commercial pit); in Louisiana there are seven facilities (5 land treatment, 1 incinerator, and 1 chemical stabilization facility); and in Alabama there are two landfarm/landtreatment facilities. Included in these numbers are one site in Texas and two sites in Louisiana that process naturally occurring radioactive material (NORM)-contaminated oil field wastes (MMS, 1998).

Reserve Pit

During drilling on land, a pit is usually constructed onsite to hold drill cuttings and extra drilling fluid. Depending on geology and hydrogeology, states might require reserve pits to be lined with geosynthetic or synthetic liners. Often the pit is intended only as a temporary holding vessel for drilling waste before being moved offsite for treatment and disposal; however, at some sites the reserve pit is used as the final disposal site. When used as a disposal method after drilling is completed, the liquid is removed (by suction or by evaporation if in a dry climate) and the solid remnants covered over with dirt. The liquids account for 62 percent of drilling waste by volume. Over two-thirds of the remaining drilling waste solids are disposed of by burying them onsite in the reserve pit (API, 1997).

Solidification

This is a modification of the reserve pit disposal method. When drilling is completed, a mixture of cement, flyash (from coal-fired utility boilers), and/or lime or cement kiln dust is added to the contents of the pit. The liquid in the pit does not necessarily need to be removed. The contents of the pit solidify into a concrete-like block, which immobilizes the heavy metal components. The process adds significantly to the bulk of the waste, but it prevents the mobilization of potential pollutants. In API's 1995 survey, less than 1 percent of drilling waste volumes were disposed of in this manner (API, 1997).

Landfarming or Landspreading

In this procedure, solids from the reserve pit (and potentially other solids from production) are broken up and thinly applied to soil, and tilled to mix the waste and soil. In theory, Volatile components evaporate off, metal ions bind to the clay, and heavy organic components are broken down by biological activity. State agencies do not use consistent terminology in referring to this process: some call it landfarming, others landspreading, and others use different terms. The disposal of solid wastes by spreading them on the land surface can occur either as a one-time application or in multiple applications. One-time application is most likely to be near the well site, and would most likely involve application of material from the reserve pit. Multiple applications of waste are often approved for centralized or commercial operations. In these cases, monitoring of soil constituents (e.g., pH, chlorides, and total hydrocarbons) is required by state agencies and once certain levels are reached, no more wastes may be applied on that site. In either one-time or multiple application operations, fertilizer may be added to enhance biodegradation of hydrocarbons. Land farming operations must be controlled to ensure that the hydrocarbons, salts and metals do not present a threat to groundwater or surface water, and that the hydrocarbon concentration does not inhibit biological activity. Approximately 10 percent of drilling waste solids are disposed of in landfarming operations (API, 1997; Smith, 1999).

Commercial Disposal

Offsite disposal of drilling wastes by commercial enterprises accounts for around 15 percent of drilling waste solids (API, 1997). This commercial disposal takes two formats. In major oil and gas producing areas of the country, dedicated facilities for managing exploration and production wastes exist. These facilities manage drilling waste and some associated waste streams using a range of processes from landfarming to slurry injection of solids to disposal in salt caverns. Drilling wastes from offshore that cannot be discharged (e.g., from oil-based muds) typically are barged to shore and disposed of in these commercial facilities. In areas of the country with less oil and gas activity, municipal or commercial landfills may accept drilling waste and certain other waste streams.

Reuse/Recycling

A growing share of drilling wastes are reused or recycled. It is currently estimated that around 10 percent of total drilling waste volume (solids and liquids) are reused or recycled. The liquids (mud) are reconditioned, with solids and other impurities removed, then used in the drilling of other wells. Because of the high cost of the base material, reuse of oil-based and synthetic-based muds is more common. Drilling waste is also used as landfill cover, roadbed construction, dike stabilization, and plugging and abandonment of other wells.

Associated Waste Disposal

Because associated wastes encompass such a diverse set of waste streams, generalizing about disposal options is difficult. What is appropriate for one stream may not be appropriate for another. Associated waste may be disposed of onsite or offsite. Some waste streams (e.g., waste solvents, unused acids, and painting wastes) are not unique to oil and gas exploration and production. These waste streams must be segregated from other wastes and managed the same as they would be at other industrial facilities. If these wastes exhibit hazardous characteristics they must be disposed of as RCRA hazardous wastes. (See Section VI.B. for more information on whether specific waste streams are exempt or non-exempt from RCRA hazardous waste requirements). Table 4 summarizes the general management of associated wastes across all waste streams.

Table 4: Management of Associated Wastes in 1995	
Management Technique	**Percent**
Underground Injection	58%
Commercial Facility	9%
Evaporation	8%
Recycling/Beneficial Use	8%
Municipal or Commercial Facility	4%
Landspreading	4%
Roadspreading	3%
Crude Oil Reclaimer	2%
Incineration	2%
Other (including hazardous waste disposal)	3%

Source: API, 1997. Data are based on a survey that may not fully represent a few lower producing areas of the country.

Gases

Flaring

Although most gas emissions are minimized through prevention, flaring can be used to reduce the impact of gaseous releases that are unavoidable or are too small to warrant the cost of capture. Nearly all drilling rigs and production wells are equipped with a vent and flare to release unusual pressure, and some wells that produce only a small amount of natural gas will flare it when there is no on-site use for the gas (e.g., to power engines) and no pipeline nearby to transport the gas to market. Since natural gas has economic value, flaring it is usually a last resort. Approval of state regulatory agencies is required prior to flaring.

When a gas is flared, it passes through the vent away from the well, and is burned in the presence of a pilot light. Although it is preferable to prevent the emission in the first place, flaring has benefits over simple venting of unburned material. First, by burning the gas, the health and safety risks in the vicinity of the well posed by combustible and poisonous gases like methane and hydrogen sulfide are reduced. Second, flaring reduces the potential contribution to climate change; methane is a much more potent greenhouse gas than carbon dioxide, the primary product of the combustion.

IV. WASTE RELEASE PROFILE

This section provides estimates and reported quantities of wastes released from oil and gas extraction industries. Unlike facilities covered by SIC codes 20-39 (manufacturing facilities), oil and gas extraction facilities are not required by the Emergency Planning and Community Right-to-Know Act to report to the Toxic Release Inventory (TRI). Because TRI reporting is not required for the oil and gas extraction industry, other sources of waste release data have been identified for this profile. EPA is considering expanding TRI reporting requirements in the future which may affect industries that are currently not required to report to TRI, such as oil and gas extraction.

Much of the published data on wastes generated at oil and gas extraction facilities is specific to the various oil producing regions of the United States, including onshore and offshore sites. In 1996, EPA developed effluent limitation guidelines for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Much of the information presented below was collected as supporting technical information for the guidelines. Additional data reflecting the releases of onshore wells were provided by the Pennsylvania Department of Environmental Protection.

IV.A. Available Data on Produced Water

Produced water is the largest volume waste generated in oil and gas extraction operations. In 1985, the American Petroleum Institute (API) estimated that 20.8 billion barrels of produced water were generated per year by the U.S. onshore oil and gas production industry (Souders, 1998). API conducted an updated survey of the industry in 1995. Based on preliminary results, API estimates current produced water volumes at over 15 billion barrels annually (API, 1997). The decline can be attributed primarily to a 32 percent decrease in oil production over the decade. While natural gas production has risen, natural gas wells produce much less water than do oil wells.

The concentration of contaminants in produced water varies from region to region and depends on the depth of the production zone and the age of the well, among other factors. Since most contaminants found in produced water are naturally occurring, they will vary based on what is present in the subsurface at a particular location. Three tables are presented below that indicate both the relative concentrations of pollutants and the variation that can occur among samples from different locations and product streams. Table 5 presents the results of analyses performed on produced water from **-XX-** Venango County, Pennsylvania. Table 7 presents data from natural gas wells in the Devonian formation of Pennsylvania.

Table 5: Produced Water Effluent Concentrations – Gulf of Mexico (Coastal Waters)

Pollutant	Settling Effluent	Improved Gas Flotation Effluent
	Concentrations (Micrograms/L)	
Oil and Grease	26,600	23,500
Total Suspended Solids (TSS)	141,000	30,000
Priority Organic Pollutants		
2,4-Dimethylphenol	148	148
Benzene	5,200	1,226
Ethylbenzene	110	62.18
Naphthalene	184	92.02
Phenol	723	536
Toluene	4,310	827.80
Priority Metal Pollutants		
Cadmium	31.50	14.47
Chromium	180.00	180.00
Copper	236.00	236.00
Lead	726.00	124.86
Nickel	151.00	151.00
Silver	359.00	359.00
Zinc	462.00	133.85
Other Non-Conventional Pollutants		
Aluminum	1,410	49.93
Ammonia	41,900	41,900
Barium	52,800	35,561
Benzoic acid	5,360	5,360
Boron	22,800	16,473
Calcium	2,490,000	2,490,000
Chlorides	57,400,000	57,400,000
Cobalt	117	117
Hexanoic acid	1,110	1,110
2-Hexanone	34.50	34.50
Iron	17,000	3,146
Magnesium	601,000	601,000
Manganese	1,680	74.16
2-Methylnapthalene	78	77.70
Molybdenum	121	121
n-Decane	152	152
n-Dodecane	288	288
n-Eicosane	78.80	78.80
n-Hexadecane	316	316
n-Octadecane	78.80	78.80
n-Tetradecane	119	119
o-Cresol	152	152
p-Cresol	164	164
Strontium	287,000	287,000
Sulfur	12,200	12,200
Tin	430	430
Titanium	43.80	4.48
m-Xylene	147	147
o + p-Xylene	110	110
Vanadium	135	135
Yttrium	35.30	35.30
Lead 210	5.49e-07	5.49e-07
Radium 226	1.91e-04	1.91e-04
Radium 228	9.77e-07	9.77e-07

Source: EPA Office of Water, *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, October 1996, Table VIII-7.

Table 6: Oil Well Brine (Produced Water) from Primary Recovery Operations – Venango County, Pennsylvania

Parameter	Number of Samples	Average	Minimum	Maximum	No. Samples < reporting limit
pH	28	6.4	5.2	7.4	
Osmotic pressure (milliosmoles)	18	1,445	340	2,740	2>2,000
Specific conductance (umhos/cm)	28	73,426	14,980	128,900	
Sulfates (mg/L)	13	96	1	584	10
Surfactants (mg/L)	22	1.1	0.1	2.5	2
Total Alkalinity (mg/L)	19	104	5.8	251	
Total dissolved solids (mg/L)	27	58,839	14,210	135,506	
Total suspended solids (mg/L)	19	130	20	614	
Oil & grease (mg/L)	16	18.6	2.74	78	3
Ammonia (mg/L)	17	9.3	2.22	17	
Hardness (mg/L)	27	13,075	2,199	30,720	
Calcium (mg/L)	26	3,602	10.8	6,750	
Bromide (mg/L)	17	283	57	538	
Chlorides (mg/L)	29	33,356	6,350	63,700	
Magnesium (mg/L)	28	670	87	1820	
Sodium (mg/L)	27	13,417	6	26,700	
Aluminum (µg/L)	15	730	156	1730	1
Arsenic (µg/L)	15	273	24	992	9
Barium (mg/L)	29	55.7	0.04	670	
Beryllium (µg/L)	11	11.4	0.2	95	11
Cadmium (µg/L)	5	36	0.3	150	19
Copper (µg/L)	16	78	15	264	9
Iron (mg/L)	27	34	3.97	140	
Lead (µg/L)	4	288	13.9	910	19
Manganese (µg/L)	27	1,294	175	7,500	
Nickel (µg/L)	9	150	26	790	16
Silver (µg/L)	8	2,676	0.59	21,100	12
Zinc (µg/L)	11	93	14	310	5
Lithium (µg/L)	22	1,418	273	3,660	1
Phenols (µg/L)	16	454	28	875	
Benzene (µg/L)	12	1,907	79	3,236	
Toluene (µg/L)	10	1,885	540	3,214	
Ethylbenzene (µg/L)	7	107	55	174	2
Xylene (µg/L)	11	1,057	200	2,117	

Source: Pennsylvania DEP, *Draft Oil Brine Characteristics Report*, 1999.

Table 7: Gas Well Brine (Produced Water) Characteristics – Devonian Formation of Pennsylvania

Parameter	Range	Number of Samples
pH	3.1 - 6.47	16
Specific Conductance (umhos/cm)	136,000 - 586,000	12
Pollutants (mg/L)		
Alkalinity	0 - 285	13
Bromide	150 - 1149	5
Chloride	81,500 - 167,448	22
Sulfate	<1.0 - 47	13
Surfactants	0.08 - 1200	13
Total dissolved solids	139,000 - 360,000	15
Total suspended solids	8 - 5484	5
Aluminum	<0.50 - 83	19
Arsenic	<0.005 - 1.51	5
Barium	9.65 - 1740	28
Cadmium	<0.02 - 1.21	19
Calcium	9400 - 51,300	19
Copper	<0.02 - 5.0	14
Iron	39.0 - 680	21
Lead	<0.20 - 10.2	18
Lithium	18.6 - 235	18
Magnesium	1300 - 3900	18
Manganese	3.59 - 65	21
Nickel	<0.08 - 9.2	18
Potassium	149 - 3870	16
Silver	0.047 - 7.0	4
Sodium	37,500 - 120,000	21
Zinc	<0.02 - 5.0	20

Source: Pennsylvania DEP, 1999.

IV.B. Available Data on Drilling Waste for the Oil and Gas Extraction Industry

According to API, 361 million barrels of drilling waste were produced in 1985. Due to a reduction in the number of wells drilled, for 1995 API preliminary findings indicate an estimated 146 million barrels of drilling waste (API, 1997). Drilling fluids (muds and rock cuttings) are the largest sources of drilling wastes. For offshore Gulf of Mexico, EPA estimates from 1993 assumed that 7,861 barrels of drilling fluids and 2,681 barrels of cuttings are discharged overboard per exploratory well, and 5,808 barrels of drilling fluids and 1,628 barrels of cuttings are discharged per development well (USEPA, 1993b). The different volumes are based on the average depths for the two types of wells. These volumes exclude the volumes of any drilling wastes not discharged offshore but transported to shore for disposal. Historically, on average, about 12 percent of the mud and 2 percent of the cuttings fail permit limits (USEPA, 1993b) and thus cannot be discharged. Table 8 below summarizes some of the characteristics of drilling waste in Cook Inlet, Alaska as reported in the *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*. Table 9 presents the characteristics of drilling fluids used in the drilling of gas wells into the Devonian formation of Pennsylvania.

Table 8: Cook Inlet Drilling Waste Characteristics

Waste Characteristics	Value
Percent of cuttings in waste drilling fluid	19%
Average density of dry cuttings	980 pounds per barrel
Average density of waste drilling fluid	420 pounds per barrel
Percent of dry solids in waste drilling fluid, by volume	11%
Average density of dry solids in waste drilling fluids	1,025 pounds per barrel
Drilling Fluid Pollutant Concentration Data	
Conventionals	**mg/kg drilling fluid**
Total Oil	142
Total Suspended Solids (TSS)	269,042
Priority Metals	
Cadmium	1.1
Mercury	0.1
Antimony	5.7
Arsenic	7.1
Beryllium	0.7
Chromium	240
Copper	18.7
Lead	35.1
Nickel	13.5
Selenium	1.1
Silver	0.7
Thallium	1.2
Zinc	200.5
Priority Organics	
Naphthalene	0.008
Fluorene	0.134
Phenanthrene	0.020
Non-Conventional Metals	
Aluminum	9,069.9
Barium	120,000
Iron	15,344.3
Tin	14.6
Titanium	87.5
Non-Conventional Organics	
Alkylated benzenes (a)	5.004
Alkylated naphthalenes (b)	0.082
Alkylated fluorenes (b)	0.290
Alkylated phenanthrenes (b)	0.034
Total byphenyls (b)	0.324
Total dibenzothiophenes	0.001

Source: EPA Office of Water, 1996, Table VII-4.

Table 9: Drilling Fluids Characteristics – Devonian Gas Wells				
Parameter	**Average**	**Range**	**# Samples Above Detection Limits**	**# Samples Below Detection Limits**
pH	9.57	3.1 - 12.2	61	
Osmotic pressure (mosm)	76	4.3 - 629	32	
Specific Conductance (umhos/cm)	4,788	383 - 38,600	62	
Pollutants (mg/L)				
Oil & grease	11.9	2.3 - 38.8	20	2
Alkalinity	276	18 - 1,594	60	0
Bromide	10.2	2 - 56.1	30	4
Chloride	1,547	12 - 14,700	62	0
Phenols	0.288	0.025 - 0.137	19	3
Sulfate	144	6 - 785	46	0
Surfactants	25	1.5 - 200	23	13
Total dissolved solids	3,399	386 - 24,882	61	0
Total suspended solids	87	2 - 395	34	0
Aluminum	4.601	0.170 - 16.9	17	16
Arsenic	0.032	0.00082 - 0.117	21	13
Barium	2.5	0.078 - 37.7	37	13
Calcium	290	8.7 - 1,900	60	0
Copper	0.049	0.012 - 0.268	12	22
Iron	145	0.08 - 3,970	41	4
Lead	0.785	0.07 - 3.46	5	29
Lithium	0.46	0.037 - 2.04	8	12
Magnesium	59	0.12 - 1,700	61	1
Manganese	2.284	0.01 - 46.6	40	20
Nickel	0.945	0.025 - 2.4	7	27
Silver	0.035	0.035	1	7
Sodium	777	53.7 - 5,800	59	0
Zinc	0.502	0.014 - 1.55	14	20
Source: Pennsylvania DEP, 1999.				

IV.C. Available Data on Miscellaneous and Minor Wastes (Associated Wastes)

Associated wastes are a relatively small but significant category of waste from the oil and gas extraction industry. The term "associated wastes" encompasses a wide range of small volume waste streams essential to oil and gas extraction. Because of their nature, these waste streams are the most likely to contain constituents of concern. Preliminary data from a 1995 survey estimate that 22 million barrels of associated wastes are generated annually (API, 1997). Four particular associated waste streams are discussed below.

IV.C.1. Workover, Treatment, and Completion Fluids

Well maintenance, including workover, treatment, and completion, requires the use of fluids similar to drilling fluid and is the largest miscellaneous source of waste. These fluids may contain a range of chemicals (depending on the maintenance activity undertaken) and naturally occurring materials (i.e., trace metals). Because of the presence of these constituents, the wastes require proper disposal. Onshore, most of these wastes are disposed of through Class II injection wells. Offshore, they may be discharged if they meet the standards in applicable NPDES permits. Otherwise, they are barged to shore and typically disposed of in an injection well. Table 10 presents the relative amounts of liquid and solid wastes from well maintenance operations. Table 11 contains the range and average pollutant concentrations from workover, treatment and completion fluid samples collected from wells in Texas, New Mexico, and Oklahoma.

Table 10: Typical Volumes from Well Treatment, Workover, and Completion Operations

Operation	Type of Material	Estimated Waste Volume (barrels)
Completion and Workover	Completion/Workover Fluids	200 to 1000
	Formation Sand	1 to 50
	Filtration Solids	10 to 50
	Excess Cement	<10
	Casing Fragments	<1
Well Treatment	Neutralized Spent Acids	10 to 500
	Completion/Workover Fluids	10 to 200

Source: EPA Office of Water, 1996, Table IX-2.

Table 11: Pollutant Concentrations in Treatment, Workover, and Completion Fluids

Pollutant Parameter	Pollutant Concentration (Micrograms/L)	
	Range	Average
Conventionals		
Oil and Grease	15,000 - 722,000	231,688
Total Suspended Solids	65,500 - 1,620,000	520,375
Priority Pollutant Organics		
Benzene	477 - 2,204	1,341
Ethylbenzene	154 - 2,144	1,149
Methyl Chloride (Chloromethane)	0 - 57	29
Toluene	298 - 1,484	891
Fluorene	0 - 123	62
Naphthalene	0 - 1,050	525
Phenanthrene	0 - 128	64
Phenol	255 - 271	263
Priority Pollutant Metals		
Antimony	0 - 148	29.60
Arsenic	0 - 693	166
Beryllium	0 - 25.1	8.64
Cadmium	7.6 - 82.3	26.08
Chromium	48 - 1,320	616.82
Copper	0 - 1,780	277.20
Lead	0 - 6,880	1,376
Nickel	0 - 467	115.52
Selenium	0 - 139	42.94
Silver	0 - 8	1.60
Thallium	0 - 67.3	13.46
Zinc	0 - 1330	362.94
Other Non-Conventionals		
Aluminum	0 - 13,100	6,468.40
Barium	66.5 - 3,360	498.10
Boron	4,840 - 45,200	15,042
Calcium	1,070,000 - 28,000,000	10,284,000
Cobalt	0 - 40.9	8.18
Cyanide	0 - 52	52
Iron	7,190 - 906,000	384,412
Manganese	187 - 18,800	5,146
Magnesium	10,400 - 13,500,000	5,052,280
Molybdenum	0 - 167	63
Sodium	7,170,000 - 45,200,000	18,886,000
Strontium	21,100 - 343,000	142,720
Sulfur	72,600 - 646,000	245,300
Tin	0 - 135	27
Titanium	0 - 283	74.58
Vanadium	0 - 4,850	1,156
Yttrium	0 - 131	41.92
Acetone	908 - 13,508	7,205
Methyl Ethyl Ketone (2-Butanone)	0 - 115	58
m-Xylene	335 - 3,235	1,785
o+p-Xylene	161 - 1,619	890
4-Methyl-2-Pentanone	198 - 5,862	3,028
Dibenzofuran	136 - 138	137
Dibenzothiophene	0 - 222	111
n-Decane	0 - 550	275
n-Docosane	237 - 1,304	771
n-Dodecane	0 - 1,152	576
n-Eicosane	0 - 451	226
n-Hexacosane	173 - 789	481
n-Hexadecane	0 - 808	404
n-Tetradecane	513 - 1,961	1,237
p-Cymene	0 - 144	72
Pentamethylbenzene	0 - 108	54
1-Methylfluorene	0 - 163	82
2-Methylnaphthalene	0 - 1,634	817

Source: EPA Office of Water, 1996, Table IX-7.

IV.C.2. Minor Wastes

Smaller waste streams of concern for the oil and gas extraction industry that are discussed below are drainage from drilling and production sites, solids brought to the surface with oil and gas (produced sand, also referred to as tank bottoms), and domestic and sanitary wastes at coastal and offshore sites.

Deck Drainage

Drainage from the production site, or *deck drainage*, is a concern particularly in areas with high precipitation. When water from rainfall or from equipment cleaning comes in contact with oil-coated surfaces, the water becomes contaminated and must be treated and disposed of. The fluids can contain oil from leaking equipment, wastes from cleaning operations, and spilled chemicals from treatment processes. Some locations will collect deck drainage, treat it separately in a skim tank, and discharge it, while others might combine the water with produced water and dispose of the fluids together. In the coastal areas of the Gulf of Mexico, the average facility generates approximately 12,000 barrels of deck drainage each year, but this figure would be significantly lower for facilities in drier climates (EPA, 1996).

Produced Sand

Produced sand consists of the accumulated formation sands and other particles generated during production as well as the slurried particles used in hydraulic fracturing. The waste stream also includes sludges produced from chemical flocculation procedures during produced water treatment. Produced sand typically contains crude oil. The amount will vary based on the handling and separation processes used, but can comprise as much as 19 percent by volume (EPA, 1996). Table 12 presents an analysis of samples of basic sediment taken from pits containing produced water in Pennsylvania. Like for produced water, it should be noted that concentrations will vary for different locations, particularly with respect to Naturally Occurring Radioactive Material (NORM).

Table 12: Pollutant Concentrations in Produced Water Pit Sediments in Pennsylvania

Material	Range (mg/L)	Average (mg/L)	# Samples Above Detection Limits	# Samples Below Detection Limits
Oil and Grease (mg/kg)	640 - 540,000	68,056	49	0
Arsenic	<0.01 - 0.031		19	32
Barium	0.07 - 19.1	1.8	51	0
Cadmium	<0.05		0	51
Chromium	<0.05		0	51
Lead	<0.1 - 0.27		4	47
Mercury	<0.001		0	51
Selenium	<0.01 - 0.016		8	43
Silver	<0.05		0	51
Benzene	0.0006 - .25		25	21
Toluene	0.001 - 0.27		25	21
Ethylbenzene	0.0013 - 0.049		17	29
Naphthalene	0.001 - 0.076		5	41
Xylene	.0011 - 1.78		34	12
Naturally-Occurring Radioactive Materials				
Natural Uranium (µg/kg)	873.87-2,945.97	1,658.86	9	0
^{226}Radium (pCi/kg)	6.57 - 1,344.88	593.8196	23	0
^{228}Radium (pCi/kg)	13.8 - 1639.11	770.3883	23	0
^{54}Manganese (pCi/kg)	0		0	23
^{59}Iron (pCi/kg)	0		0	23
^{58}Cobalt+^{60}Cobalt (pCi/kg)	0		0	23
^{65}Zinc (pCi/kg)	0		0	23
^{95}Zirconium (pCi/kg)	0		0	23
^{95}Niobium (pCi/kg)	0		0	23
^{131}Iodine (pCi/kg)	0		0	23
^{137}Cesium (pCi/kg)	0 - 46	17.15789	19	4
^{140}Barium (pCi/kg)	0		0	23
^{140}Lanthanum (pCi/kg)	0		0	23
Thorium (total) (pCi/kg)	860 - 4,868	2,908.826	23	0

Source: PA DEP, *Characterization and Disposal Options for Oilfield Wastes in Pennsylvania*, 1994.

Domestic and Sanitary Wastes

Domestic and sanitary wastes are issues at coastal and offshore sites. Domestic wastes are water from sinks, showers, laundry, and food preparation areas. Domestic waste also includes solid materials such as paper and cardboard which must be disposed of properly. Because domestic waste does not contain fecal coliform bacteria, most NPDES permits allow untreated discharge so long as floating solids are not produced. Sanitary wastes are generated from toilets, and must be either treated or stored for disposal on land. Most offshore facilities treat the wastes through a combination of chlorination and biological digesters or physical maceration, and discharge the waste at the site. Offshore facilities discharge an average of approximately 2,050 barrels of domestic/sanitary waste per facility per year (EPA, 1996).

IV.D. Other Data Sources

The Aerometric Retrieval System (AIRS) is an air pollution data delivery system managed by the Technical Support Division in EPA's Office of Air Quality Planning and Standards (OAQPS), located in Research Triangle Park, North Carolina. The AIRS is a national repository of data related to air pollution monitoring and control. The AIRS contains a wide range of information related to stationary sources of air pollution, including the emissions of a number of air pollutants which may be of concern within a particular industry. Table 13 summarizes annual releases (from the industries for which Sector Notebook Profiles have been prepared) of carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter of 10 microns or less (PM10), particulate matter, all sizes reported in lieu of PM10 (PT), sulfur dioxide (SO_2), and volatile organic compounds (VOCs).

Table 13: Air Pollutant Releases by Industry Sector (tons/year)

Industry Sector	CO	NO_2	PM10	PT	SO_2	VOC
Metal Mining	4,951	49,252	21,732	9,478	1,202	119,761
Oil and Gas Extraction	**132,747**	**389,686**	**4,576**	**3,441**	**238,872**	**114,601**
Non-Fuel, Non-Metal Mining	31,008	21,660	44,305	16,433	9,183	138,684
Textiles	8,164	33,053	1,819	38,505	26,326	7,113
Lumber and Wood Products	139,175	45,533	30,818	18,461	95,228	74,028
Wood Furniture and Fixtures	3,659	3,267	2,950	3,042	84,036	5,895
Pulp and Paper	584,817	365,901	37,869	535,712	177,937	107,676
Printing	8,847	3,629	539	1,772	88,788	1,291
Inorganic Chemicals	242,834	93,763	6,984	150,971	52,973	34,885
Plastic Resins and Man-made Fibers	15,022	36,424	2,027	65,875	71,416	7,580
Pharmaceuticals	6,389	17,091	1,623	24,506	31,645	4,733
Organic Chemicals	112,999	177,094	13,245	129,144	162,488	17,765
Agricultural Chemicals	12,906	38,102	4,733	14,426	62,848	8,312
Petroleum Refining	299,546	334,795	25,271	592,117	292,167	36,421
Rubber and Plastic	2,463	10,977	3,391	24,366	110,739	6,302
Stone, Clay, Glass and Concrete	92,463	335,290	58,398	290,017	21,092	198,404
Iron and Steel	982,410	158,020	36,973	241,436	67,682	85,608
Metal Castings	115,269	10,435	14,667	4,881	17,301	21,554
Nonferrous Metals	311,733	31,121	12,545	303,599	7,882	23,811
Fabricated Metal Products	7,135	11,729	2,811	17,535	108,228	5,043
Electronics and Computers	27,702	7,223	1,230	8,568	46,444	3,464
Motor Vehicle Assembly	19,700	31,127	3,900	29,766	125,755	6,212
Aerospace	4,261	5,705	890	757	3,705	10,804
Shipbuilding and Repair	109	866	762	2,862	4,345	707
Ground Transportation	153,631	594,672	2,338	9,555	101,775	5,542
Water Transportation	179	476	676	712	3,514	3,775
Air Transportation	1,244	960	133	147	1,815	144
Fossil Fuel Electric Power	399,585	5,661,468	221,787	13,477,367	42,726	719,644
Dry Cleaning	145	781	10	725	7,920	40

Source: EPA Office of Air and Radiation, AIRS Database, 1997.

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POLLUTION PREVENTION OPPORTUNITIES

The best way to reduce pollution is to prevent it in the first place. Some companies have creatively implemented pollution prevention techniques that improve efficiency and increase profits while at the same time minimizing environmental impacts. This can be done in many ways such as reducing material inputs, re-engineering processes to reuse by-products, improving management practices, and employing substitution of toxic chemicals. Some smaller facilities are able to actually get below regulatory thresholds just by reducing pollutant releases through aggressive pollution prevention policies.

The Pollution Prevention Act of 1990 established a national policy of managing waste through source reduction, which means preventing the generation of waste. The Pollution Prevention Act also established as national policy a hierarchy of waste management options for situations in which source reduction cannot be implemented feasiblely. In the waste management hierarchy, if source reduction is not feasible, the next alternative is recycling of wastes, followed by energy recovery, with waste treatment as a last alternative.

In order to encourage these approaches, this section provides both general and company-specific descriptions of some pollution prevention advances that have been implemented within the oil and gas extraction industry. While the list is not exhaustive, it does provide core information that can be used as the starting point for facilities interested in beginning their own pollution prevention projects. This section provides summary information from activities that may be, or are being implemented by this sector. When possible, information is provided that gives the context in which the technique can be used effectively. Please note that the activities described in this section do not necessarily apply to all facilities that fall within this sector. Facility-specific conditions must be carefully considered when pollution prevention options are evaluated, and the full impacts of the change must examine how each option affects air, land and water pollutant releases.

Waste Management Plans

Pollution prevention opportunities are most effective when they are coordinated in a facility-wide waste management plan. The American Petroleum Institute (API) has published guidelines for waste management plans, in which pollution prevention is an integral part (API, 1991). The ten-step plan involves the following:

1. Company management approval: Management should establish goals for the waste management plan, identify key personnel and resources that are

committed to the plan, and develop a mission statement for its environmental policies.

2. Area Definition: The waste management plan should be designed for a specific area to account for differing regulations and conditions; in most cases, the area would be limited to within one state.

3. Regulatory Analysis: Federal, state and local laws, and landowner and lease agreements, should be evaluated. Based on these evaluations, operating conditions and requirements should be defined.

4. Waste Identification: The source, nature, and quantity of generated wastes within the plan's area should be identified, and a brief description of each type of waste should be written.

5. Waste Classification: Each waste stream should be classified according to its regulatory status, including whether it is a hazardous waste subject to regulation under the Resource Conservation and Recovery Act (RCRA).

6. List and Evaluate Waste Management and Disposal Options: List all waste management practices and determine the environmental acceptability of each option. Consider regulatory restrictions, engineering limitations, economics, and intangible benefits when determining their feasibility.

7. Waste Minimization: Analyze each waste-generating process for opportunities to reduce the volume generated or ways to reuse or recycle wastes. Note that the waste minimization or pollution prevention opportunities that are presented in this section can be used for this step.

8. Select Preferred Waste Management Practices: Choose the preferred management practices identified in Step 6 and incorporate waste minimization options from Step 7 wherever feasible. Specific instructions for implementation should be developed.

9. Prepare and Implement an Area Waste Management Plan: Compile all preferred waste management and minimization practices and write waste management summaries for each waste. Implement the plan on a field level.

10. Review and Update Waste Management Plan: Establish a procedure to periodically review and revise the plan.

V.A. Exploration

Several approaches or technologies can be used by exploration companies to drill more efficiently and to maximize the recovery of oil and natural gas. Oil and gas Exploration is not a waste-intensive activity per se, but efforts made by those involved with exploration can assist in minimizing the number of dry wells that are later drilled.

Drill Site Selection

The volume of drilling waste is directly related to the number of wells drilled. Thus, if fewer wells can be drilled to efficiently produce a discovered reservoir, and if the number of dry holes (wells drilled that do not find commercial quantities of oil or gas) can be minimized, then the total volume of drilling wastes will be reduced. Site selection is a key component of this reduction.

<u>Modeling Software</u>
New computer software is available that converts seismic data into models of subterranean formations. Until 15 years ago, modeling software was limited to large mainframe computers and was inaccessible for small-scale projects. In recent years, software has been created for use on personal computers that can incorporate the various components of remote sensing and logging. Three-dimensional models can now be produced from data that geophysicists previously would have had to analyze manually.

> The U.S. Department of Energy has created several significant computer programs for the oil and gas exploration industry. KINETICS models the chemical reactions that take place over millions of years that lead to the creation of oil and gas, and therefore assists in interpreting whether conditions at a site are favorable for oil. Programs like BOAST and MASTER can be used in wells already in production to model flow patterns to determine the best approach for secondary or tertiary recovery efforts. It is estimated that computer programs such as these can result in an increase of three billion barrels of domestic reserves, generate increased tax revenue for the government, and reduce the drilling of unnecessary or unproductive wells (U.S. Department of Energy, 1998).

<u>Iodine Sensing</u>
Empirical evidence indicates that unusual concentrations of iodine on the earth's surface are nearly always associated with petroleum that seeps from subsurface formations. Although the process is still in the experimental stage, surface geochemical analyses can be performed to test for the presence of unusually high concentrations of iodine, which in turn indicates the presence of oil or gas. The iodine test can be used in conjunction with traditional

seismic processes to determine favorable drilling sites. Seismic tests measure for geological formations that can potentially contain large amounts of oil or gas, but can't directly detect these products. Conversely, high iodine levels may indicate that petroleum is present, but not that the geological structures are favorable for petroleum extraction. These two processes therefore can be used in conjunction with each other to better determine the probability of being able to produce oil at a given site before a well is drilled.

Drill Site Construction

Storm Water Runoff Impact Reduction

Measures that can be taken to reduce the impacts associated with storm water runoff can apply to all aspects of oil and gas exploration and production. The following are a few examples of such measures.

- Reduce exposure of materials such as drilling fluids and other chemicals stored on-site to rainfall and storm water runoff. This can be accomplished by storing drums and other materials under cover (such as in a trailer, in a shed or covering with tarps).
- Utilize best management practices (BMPs) such as diversion dikes, containment diking, and curbing to reduce exposure of storm water runoff to cuttings and other waste storage areas.
- Utilize BMPs such as sediment traps, swales, and mulching during construction activities (such as during road building or construction of buildings) to reduce loss of sediment and contamination of runoff.
- Insure that adequate materials and equipment are available to contain and control spills in order to prevent contamination of runoff. An effort should be made here to go beyond any SPCC requirements and be prepared to contain and control all spills (of any waste) on site.

Two references that may be useful for oil and gas exploration and production operations to prevent contamination of storm water runoff are 1) Storm Water Management for Industrial Activities - Developing Pollution Prevention Plans and Best Management Practices (EPA 832-R-92-006) and 2) Storm Water Management for Construction Activities - Developing Pollution Prevention Plans and Best Management Practices (EPA 832-R-92-005).

Downhole Analysis

Recently, several technologies have emerged that allow for more accurate analysis of an oil or gas-bearing formation via equipment lowered into the wellbore of producing wells. These either can lead to improvements in production of the well in question, or assist in determining the best location for an additional well. In either case, the technology helps to reduce the number of wells drilled that do not produce.

<u>Formation Analysis Through Old Well Casings</u>
Some of the geophysical logging procedures and tools now in use for new wells were not available for wells drilled 30 years ago. Therefore, data for the zones between the surface and the production zone of the well may be incomplete. Typically the metal casing limits analysis of the formations in these sealed-off zones. New tools have been developed that allow surveying through casing and that may lead to the discovery of production zones that were missed during the original drilling. The procedure can extend the life of old wells and reduce the need for drilling new ones.

<u>Crosswell Seismic Imaging</u>
Geological imaging techniques via the surface are limited by the thousands of feet of rock between the equipment and the potential production zone. As a result, the best resolution obtainable is approximately 50 feet. With crosswell seismic imaging, sound wave generators and receivers are lowered into several wellbores in a production field. Because the waves need to travel a shorter distance between the generator and receivers, the resolution can be as accurate as five feet. This process can be useful in ensuring that additional wells drilled in a producing field are placed accurately.

V.B. Well Development

Drilling

<u>Closed Loop Drilling Fluid System</u>
When drilling a well that will be shallow and likely will not encounter unusual zones of pressure, a closed system for drilling fluids can be used. At a conventional drilling site, drilling fluid is circulated through the wellbore, then deposited in a reserve pit dug next to the well. This pit is open to the atmosphere, and serves to store excess fluid and to separate out contaminants. While the large storage capacity is important for wells that encounter high pressure and therefore might experience fluctuations in the amount of fluid needed, a reserve pit can be the source of considerable costs at a drilling site. The pit itself must be constructed at the beginning of drilling, and must be closed properly when drilling is completed. Also, because the pit may release higher levels of VOCs and can leak liquids into surface or groundwater, there are increased health, environmental, and financial risks.

In a closed-loop drilling fluid system, the reserve pit is replaced with a series of storage tanks. The tanks represent an additional cost, but because they preclude the need for constructing a pit, reduce the amount of environmental releases, and result in more efficient use of drilling fluid, the technology can save the operator money when conditions allow its use.

A small independent operator in Texas was concerned that reserve pits for drilling fluid were increasing waste management costs and exposing it to liability for surface and ground water contamination. Because the wells to be drilled were relatively shallow and few complications were expected, the operator negotiated with the drilling contractors to use a closed-loop fluid system. The operator realized savings of about $10,000 per well because reserve pits were not constructed and waste management costs were reduced. The operator's liability was also reduced (Texas Railroad Commission, 1997).

<u>Pit Design</u>

If the closed-loop drilling system is not used for drilling fluids, another approach may be to use a V-shaped pit instead of the traditional rectangular pit. The open end of the "V" faces the drilling rig and the cross-sectional view resembles a squared-off funnel (about 10 feet deep with the upper 5 feet having slanted walls to a width of about 20 feet). Because the fluid must travel the full length of the pit, this design prevents mud from channeling between the discharge point and the suction point, and reduces the amount of water that needs to be added to maintain the desired fluid characteristics. In addition, because the V-shaped pit is long and narrow, it is easier to construct and leaves a smaller "footprint" at the site.

A company installed a V-shaped reserve pit and compared the costs with those incurred at similar-sized wells using a traditional pit. The company determined that pit construction time was reduced by about 40 percent, water costs for the well were reduced by about 38 percent, and pit liner costs were reduced by about 43 percent. The total cost savings were about $10,800 per well (Texas Railroad Commission, 1999).

<u>Substitution of Drilling Fluid Additives</u>

Some traditional drilling fluid additives are toxic and require extra care in disposal. In response, the drilling fluid industry has developed replacements for some of the more toxic compounds. These include:

- Replacement of chrome lignosulfonate dispersants with chrome-free lignosulfonates and polysaccharide polymers.

- Use of amines instead of pentachlorophenols and paraformaldehyde as biocides.

- Lubrication with mineral oil and lubra-beads instead of diesel oil.

Substitutions such as those described above can minimize the toxicity of drilling wastes and reduce the risks and costs associated with drilling fluid disposal.

Material Balance and Mud System Monitoring
Monitoring devices used at various points in the drilling fluid circulation system may be used to check for the decrease of fluid levels or other changes in fluid characteristics. Such devices may reduce the need for the addition of water and additives to the fluid, thereby reducing the costs and waste associated with drilling fluid.

Removal of Solids from Drilling Fluid
Careful removal of drill cuttings and other contaminating solids can reduce the need to dilute or replace drilling fluid. Furthermore, if the separated solids are treated thoroughly to remove moisture, the weight of waste can be significantly reduced. In addition to using shale shakers, which are always used to remove rocks and larger fragments, drilling rigs can reduce waste by including several optional components in their mud treatment systems. Desanders and desilters separate increasingly smaller particles. Centrifuges remove the smallest suspended pieces. Finally, mud cleaners break oil-water emulsions and remove many dissolved components. If these devices are in optimal working condition, the drilling mud can be nearly free of suspended materials, and the solid waste can be less than 30 percent moisture by weight.

Polycrystalline Diamond Compact (PDC) Drill Bit
Pulling the drill string to replace the drill bit is one of the more inefficient and potentially dangerous procedures in drilling. Quite a bit of time and energy can be wasted in pulling the entire drill string to the surface and lowering it back into the wellbore. In addition, it is when the drill string is being raised and lowered that well blowouts are an increased risk if not properly done. It is therefore desirable for both efficiency and blowout prevention to minimize drill bit replacement.

PDC bits have been viable commercially for about a decade, and are the most durable bits available. The bit is primarily steel with interlocked diamond studs. The bits typically last between 230 and 260 drilling hours, but have lasted over 1,000 hours without replacement. Because of their durability, diamond bits account for one-third of the drill bit market, and can save drilling companies as much as $1 million per well (U.S. Department of Energy, 1998).

Downhole Drilling Telemetry
Traditionally, drillers have determined the position of the drill bit by removing the drill string from the well, lowering an instrument into the wellbore, retrieving the instrument, then lowering the drill string back into the wellbore. This process is inefficient and increases the risk of a blowout.

The Department of Energy has helped to develop a wireless system that sends pulses through the drilling mud from the drill bit to the surface, in a process called *mudpulse telemetry*. The technology presents several benefits for wells in which its use is practical: data can be collected during drilling, the data are more complete than those from periodic measurements because the pulsing can occur continuously, and advance warnings can be received of impending drill hazards. Without considering the benefit of decreased environmental and health risks, mudpulse technology saves the industry over $400 million per year.

Horizontal Drilling

Oil and natural gas bearing formations typically have a small vertical profile (i.e., are confined to a narrow range of depth), but are spread over a large horizontal area. As a result, wellbores that intersect the oil-producing formation at an angle can drain more of the formation and reduce the need to drill additional wells compared to purely vertical wells.

Horizontal drilling is costly, because it requires advanced geological sensing equipment and constant attention to the placement of the drill bit. However, the increased cost is often more than offset by increased production and the reduced need for drilling multiple wells.

In the Dundee Formation of Michigan, as much as 85 percent of the known oil remained in the formation after many years of production. Many wells were on the verge of being plugged, with production near five barrels of oil per day per well. A DOE co-sponsored project drilled a horizontal well in the formation, which produced 100 barrels per day, and had estimated recoverable reserves of 200,000 barrels of oil. The program attracted other well developers, and 20 to 30 additional horizontal wells are being drilled in the formation. It is estimated that the application of horizontal drilling to this formation may yield an additional 80 to 100 million barrels of oil (Department of Energy, 1998).

Reuse of Drilling Fluids

Drilling fluid is often disposed of when a well is completed, and fresh fluid used for any adjacent wells. Filtration processes have allowed drilling fluid to be reconditioned, so that it can be used for multiple wells before being discarded. Other possible uses for used drilling fluids are to plug unproductive wells or to spud in new wells. Reuse of oil-based and synthetic-based drilling fluids to drill additional wells is common because of the high cost of the base fluids.

One drilling company in Alaska sought to filter and recondition its drilling fluid in order to use it for several wells. The fluid was used on average over two times, resulting in a decrease of fluid used from 50,000 barrels of fluid to 22,000 barrels. Because the cost of filtering is only six percent of the cost of purchasing new fluid, the fluid treatment system reduced the fluid costs for this operator from $7 million to $3.25 million (SAIC, 1997).

Preventive Maintenance and Leak Containment

Engines, tanks, pumps and other equipment used in the drilling process may leak lubricating oil or fuel. Soil contamination and waste generation may be avoided and valuable chemicals may be recovered by performing regular preventive maintenance and installing leak containment devices. Examples of preventive maintenance include routine checks and replacement of leaking valves, hoses, or connections, while containment measures may include the installation of drip pans underneath engines, containers, valves, and other potential sources of leaks. These practices and devices are important pollution prevention options at production and maintenance operations as well as at drilling sites.

Inventory Control

Facilities may maintain an excess on-site volume of chemicals and materials. This may lead to unnecessary regulatory compliance concerns, operating costs, and waste generation. By tracking the inventory of chemicals and materials, particularly with the use of computer programs, an operator may use materials more efficiently and reduce waste generation. In addition, an operator may negotiate with vendors to accept empty and partially-filled containers for reclamation and reuse, because commercial chemical products that are returned to a vendor or manufacturer may not be considered solid wastes.

An operation encompassing drilling, gas production, and compression activities determined that its on-site supply of chemicals was excessive and that much of its hazardous waste generation was unnecessary. The company made several changes: it identified alternative, less toxic chemicals; eliminated the use of organic solvents; identified processes for which individual chemicals could be used in multiple situations; established a purchasing procedure in which a new chemical is purchased only after evaluating information including material safety data sheets (MSDSs) and other information sources supplied by vendors; and tracked all purchased chemicals to ensure efficient usage. As a result of the program, the company eliminated the use of 32 unnecessary chemicals and products, reduced regulatory concerns, minimized waste disposal costs, and achieved the cooperation of vendors, who worked to supply the company with satisfactory chemicals (Texas Railroad Commission, 1999).

Completion

Lead-Free Pipe Dope
Pipe dope is used in drill string connections. The American Petroleum Institute (API)-specified pipe dope contains approximately 30 percent lead, which raises human health and environmental concerns. New lead-free, biodegradable pipe dopes are now available, however, which may be used when conditions do not require the use of the API-specified material. In particular, the use of pipe dope on thread protectors may allow for the recycling of thread protectors with fewer regulatory concerns.

Cementing "On-the-Fly"
When well casing is cemented in, the cement used is often pre-mixed with additives to specification. There may be a substantial surplus of unused, pre-mixed cement if the quantity required for the project was overestimated. One solution used by some service companies is to mix neat (concentrated) cement with additives on-the-fly, through the use of automatic density control systems. The mixing process can be stopped as soon as the cementing job is complete, and the unused raw materials can be used at a later cementing job rather than disposed of as waste. Cementing on-the-fly is becoming common practice.

V.C. Petroleum Production

Produced Water Management

Produced water constitutes the vast majority of oil and gas extraction waste, and traditionally the volume has been fixed and unavoidable. However, there have been developments that might help to reduce the amount of produced water that is brought to the surface, and reduce the wastes associated with treating produced water that does reach the surface.

Downhole Produced Water Separation
A new procedure made possible by the miniaturization of motors is the separating and pumping of produced water downhole, without bringing it to the surface. There are three significant variations, but in each case excess water is separated from the desired product in the wellbore and injected into another geological formation, typically below the production zone.

In formations where oil and water are mostly separate, two perforations in the well can be made; oil is removed through one and transported to the surface, and water is removed through the other perforation and injected in the disposal zone. It should be noted that the water disposal system must be monitored to ensure that oil is not lost.

In another method, a hydrocyclone is used downhole to separate free water from any oil- or gas-containing fluid by centrifugal force. The water is injected into a disposal zone, and the product is pumped to the surface.

Finally, in gas wells, simple gravity can be used to remove a substantial amount of water. Gas rises to the surface of the separation device, and water is injected from the bottom into a lower disposal zone.

With these methods, some water is always still brought to the surface. Also, the technology is still in development. Nevertheless, downhole separation can be an effective and economically attractive method of reducing produced water volumes.

<u>Produced Water Filter Management</u>

Many wells employ filters to remove some waste from produced water before the water is injected into an underground well. Because the water may contain varying amounts of filterable components, the filters must be changed regularly in order to prevent the system from backing up. Many wells replace the filters at fixed intervals; for example, twice a month. However, it is possible to reduce the frequency of filter changes by measuring the difference in pressure between the input and output sides of the filter, and only changing the filter when a certain pressure is reached. Costs are incurred when valves are installed, but the savings involved in labor, filters, and filter disposal often offset the cost of valve installation.

> A small independent operator wanted to reduce the number of filters used for its produced water injection system. Previously, the operator had changed the filters twice a month at its 36 injection wells, at a cost of $4,148 per year (1,700 filters at $2.44 per filter). The operator installed valves on the filter units, at a total cost of $1,800. The following year, the operator only generated 28 waste filters, and saved about $4,000 per year in filter purchases, plus additional labor time and waste management costs (Texas Railroad Commission, 1997).

Natural Gas Conditioning

<u>Reducing Glycol Circulation Rates</u>

Glycol is used to remove water from natural gas. However, methane and VOCs are removed as well, in proportion to the amount of glycol circulated through the system. These methane and VOC components are removed from the glycol during a reconditioning process, and may be either returned to the production stream or vented to the atmosphere.

Research by the EPA voluntary industry partnership Natural Gas STAR has indicated that operators often maintain a circulation rate that is at least two times higher than is needed to attain mandated water content levels. Therefore, it is desirable to perform calculations to determine the minimum circulation rate needed. Savings can be realized on several fronts:

- Less salable methane lost to the atmosphere
- Less glycol needed
- Improved dehydrator unit efficiency
- Lower fuel pump use.

The potential savings for a dehydrator unit can range from $260 to $26,280 per year (Natural Gas STAR, 1997).

Adjusting Pneumatic Devices

For both oil and gas field operations pressurized natural gas is used regularly in pneumatic devices to regulate pressure, control valves, and equilibrate liquid levels. Leaks and releases from this practice, particularly from inefficient or "high-bleed" devices, are the single largest source of methane emissions by the industry. Methane is released at the estimated rate of 31 billion cubic feet (Bcf) per year from pneumatic devices. Several strategies exist to reduce such emissions, including the replacement of high-bleed devices with equivalent low-bleed ones and maintenance of existing devices to replace leaking seals and tune valves. Natural Gas STAR estimates that partners of the program have saved 11.2 Bcf to date through improvements to pneumatic devices, saving approximately $22.4 million. For most of the improvements, the payback period is between six months and a year (Natural Gas STAR, 1997).

Energy-Efficient Production

Automatic Casing Swab

In wells where natural formation pressure is insufficient to lift the product to the surface, it might be possible to install a small device downhole to delay the purchase of costly pumping or injection equipment. The Automatic Casing Swab (ACS) seals off the production zone of the well, which causes pressure to build up in the formation. At a threshold pressure, the ACS opens, and product flows to the surface without mechanical assistance. When the flow slows and pressure decreases, the ACS closes until pressure increases again. The device was created by the Sandia National Laboratories under a grant from DOE, and as of the end of 1997 has been applied to 350 wells. These wells are producing more than 3.5 million cubic feet of natural gas per year that otherwise would have been uneconomical to extract. The device may also lead to decreased energy consumption in other wells in situations where it reduces the need for energy-intensive mechanical pumps.

Solid Waste Reduction

Oily Sludge Minimization

When oil first is brought to the surface, fine particles, oil, and water form a stable sludge that settles out in storage tanks and separation equipment. There are two approaches to minimizing the loss of product that occurs when oil becomes entrained in the sludge: preventing the formation of sludge and treating the sludge to recover the oil.

Two significant methods can minimize the formation of sludge in a storage tank at a production site. First, recirculating pumps can be installed in tanks. By increasing circulation, heavier components remain in suspension longer and do not collect on the bottom of the tanks as quickly. Second, eliminating air contact with oil in the tanks can reduce the formation of sludge. Oxygen can play a role in the formation of sludge, so minimizing the introduction of atmospheric oxygen can reduce sludge levels. Furthermore, reducing contact to the atmosphere can minimize emissions of VOCs.

In many locations, recyclers can treat sludge to remove oil at a crude oil reclamation plant. Crude oil reclamation serves two purposes; the extracted oil can be sold, and disposal costs for sludge is minimized because much of the liquid component is removed. In addition, salable material that has solidified, e.g., paraffin, may be reclaimed during this process. The separation process typically is performed with the use of centrifuges, heat, or filters. One example is a filter press, which presses solids into a cake and extracts oil and water as an aqueous filtrate. The water and oil are then separated further.

A facility on the West Coast installed a filter press to retrieve oil from sludge and reduce disposal costs. The press reduced the volume of waste from 44,900 to 13,500 barrels per year, a reduction of 70 percent. Disposal costs were reduced by $564,200 per year. Approximately 81 percent of the oil in the sludge was recovered, so that at a price of $15 per barrel, the recovered oil represented additional revenues of $108,000 per year. Based on a capital cost for the press of approximately $3,000,000 and operating costs of $400,000 per year, the system is saving approximately $272,000 per year and the capital cost has a payoff period of about 3.5 years.

V.D. Maintenance

Maintenance procedures, particularly workovers, may be a source of potential pollutants for industry including acids, VOCs, and solutions with high concentrations of salts and metals. The following opportunities describe steps that can minimize the need for workovers, or help notify operators when maintenance is necessary to limit releases.

Preplanning

Careful preplanning efforts undertaken prior to a workover may reduce the amount of materials necessary at the site, and therefore may reduce waste and the chance of spilling. For example, by estimating the amount of acid required for acid stimulation based on the known reservoir conditions, the transportation, storage, and disposal of excess acid may be reduced.

Paraffin and Scale Accumulation Prevention

The buildup of paraffins in production equipment, particularly in older wells, is a serious concern, and when untreated, paraffin buildups can damage pumping equipment and rupture flowlines. Therefore, it is desirable to minimize the buildup of paraffins. One possible solution is the installation of a magnetic fluid conditioner (MFC), which creates a strong permanent magnetic field around the pump. This magnetic field alters the solubility and viscosity of crude oil, so that paraffin, scale, and other contaminants do not precipitate in the flowlines. The device requires a significant capital investment, must be custom-made for each well, and is not always successful, but the reduced frequency of maintenance and the reduced risk of flowline rupture (and the associated mitigation costs) can make an MFC a wise choice for wells with paraffin and scale buildup problems.

A small independent operator was suffering from damaged pumping equipment and ruptured flowlines as a result of paraffin buildup, and had to treat the well every ten days with solvent/hot oil to remove the deposits. The operator installed an MFC in the well for $5,000. Seven weeks later for an unrelated reason, the operator pulled the tubing from the well, and minimal paraffin deposition was observed. The investment was recovered in six months due to reduced maintenance costs, and because flow had improved, revenue increased as well (Texas Railroad Commission, 1997).

High-level alarm

A helpful device for preventing releases and loss of product is an alarm and automatic shut-off that shuts-in production equipment when an irregularity is detected. The equipment can only be restarted manually, to ensure that the problem is addressed. A facility-wide alarm is particularly important when the operator is offsite and the well is only monitored periodically.

Microbially-Treated Produced Water

The separation of oil from produced water is not completely efficient; oil concentrations in produced water can be at least 10 ppm. This oil can clog disposal wells and increase electricity costs because injection pumps must contend with increased pressure in these clogged wells. If oil-eating microbes are introduced to the produced water, oil content can be reduced, injection wells may become clogged less frequently (thereby reducing workover costs), and electricity costs are reduced because the pump can work more efficiently.

A small operator wanted to reduce the frequency of workovers and trim electricity costs due to oil clogging in two injection wells. For approximately $150 per month for the two wells, the company added oil-scavenging microbes to the produced water. The operator realized a reduction of $400 per month in electricity costs due to the reduced pressure in the injection well, for a net savings of $250 per month. The procedure also has helped to minimize the number of injection well workovers.

Coiled Tubing Units

As mentioned in previous sections, pulling the drill string or production tubing can increase the chance of a blowout or other spills. Coiled tubing units allow workovers to be performed while keeping production tubing in place. By using coiled tubing units during workovers, the use of a workover rig and the pulling of production tubing are avoided.

Product Substitution

Many materials used in the workover process, particularly solvents used for cleaning and for paints, are classified as hazardous wastes when spent. Alternatives are available that are not classified as hazardous waste, and which are safer for the environment and present fewer regulatory concerns. Alternatives for cleaning solvents include citrus-based cleaning compounds and steam, or a substitute for the solvent Varsol (also called petroleum spirits or Stoddard solvent) is available as a “high flash point Varsol,” thereby sufficiently reducing the solution’s ignitability hazardous waste characteristic. For solvent-based paints, a common substitution is the use of water-based paints, which reduce or eliminate the need for solvents and organic thinners.

Chemical Metering or Dosing Systems

The dispensing of some workover fluids, such as corrosion inhibitors, by an occasional bulk addition can result in the inefficient use of the chemical and an inadequate workover job. As an alternative, an automatic dosing system that releases a small, continuous stream of fluid can reduce the amount of needed fluid and may improve workover results.

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VI. SUMMARY OF FEDERAL STATUTES AND REGULATIONS

This section discusses the federal regulations that may apply to this sector. The purpose of this section is to highlight and briefly describe the applicable federal requirements, and to provide citations for more detailed information. The three following sections are included:

- Section VI.A contains a general overview of major statutes
- Section VI.B contains a list of regulations specific to this industry
- Section VI.C contains a list of pending and proposed regulatory requirements.

The descriptions within Section VI are intended solely for general information. Depending upon the nature or scope of the activities at a particular facility, these summaries may or may not necessarily describe all applicable environmental requirements. Moreover, they do not constitute formal interpretations or clarifications of the statutes and regulations. For further information, readers should consult the Code of Federal Regulations and other state or local regulatory agencies. EPA Hotline contacts are also provided for each major statute.

VI.A. General Description of Major Statutes

Clean Water Act

The primary objective of the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act (CWA), is to restore and maintain the chemical, physical, and biological integrity of the nation's surface waters. Pollutants regulated under the CWA are classified as either “toxic” pollutants; "conventional" pollutants, such as biochemical oxygen demand (BOD), total suspended solids (TSS), fecal coliform, oil and grease, and pH; or "non-conventional" pollutants, including any pollutant not identified as either conventional or priority.

The CWA regulates both direct and “indirect” dischargers (those who discharge to publicly owned treatment works). The National Pollutant Discharge Elimination System (NPDES) permitting program (CWA section 402) controls direct discharges into navigable waters. Direct discharges or "point source" discharges are from sources such as pipes and sewers. NPDES permits, issued by either EPA or an authorized state (EPA has authorized 43 states and 1 territory to administer the NPDES program), contain industry-specific, technology-based and water quality-based limits and establish pollutant monitoring and reporting requirements. A facility that proposes to discharge into the nation's waters must obtain a permit prior to initiating a discharge. A permit applicant must provide quantitative analytical data identifying the types of pollutants present in the facility's effluent. The permit will then set forth the conditions and effluent limitations under which a facility may make a discharge.

Water quality-based discharge limits are based on federal or state water quality criteria or standards, that were designed to protect designated uses of surface waters, such as supporting aquatic life or recreation. These standards, unlike the technology-based standards, generally do not take into account technological feasibility or costs. Water quality criteria and standards vary from state to state, and site to site, depending on the use classification of the receiving body of water. Most states follow EPA guidelines which propose aquatic life and human health criteria for many of the 126 priority pollutants.

Storm Water Discharges

In 1987 the CWA was amended to require EPA to establish a program to address storm water discharges. In response, EPA promulgated NPDES permitting regulations for storm water discharges. These regulations require that facilities with the following types of storm water discharges, among others, apply for an NPDES permit: (1) a discharge associated with industrial activity; (2) a discharge from a large or medium municipal storm sewer system; or (3) a discharge which EPA or the state determines to contribute to a violation of a water quality standard or is a significant contributor of pollutants to waters of the United States.

The term “storm water discharge associated with industrial activity” means a storm water discharge from one of 11 categories of industrial activity defined at 40 CFR Part 122.26. Six of the categories are defined by SIC codes while the other five are identified through narrative descriptions of the regulated industrial activity. If the primary SIC code of the facility is one of those identified in the regulations, the facility is subject to the storm water permit application requirements. If any activity at a facility is covered by one of the five narrative categories, storm water discharges from those areas where the activities occur are subject to storm water discharge permit application requirements.

Those facilities/activities that are subject to storm water discharge permit application requirements are identified below. To determine whether a particular facility falls within one of these categories, the regulation should be consulted.

Category i: Facilities subject to storm water effluent guidelines, new source performance standards, or toxic pollutant effluent standards.

Category ii: Facilities classified as SIC 24-lumber and wood products (except wood kitchen cabinets); SIC 26-paper and allied products (except paperboard containers and products); SIC 28-chemicals and allied products (except drugs and paints); SIC 29-petroleum refining; SIC 311-leather tanning and finishing; SIC 32 (except 323)-stone, clay, glass, and concrete; SIC 33-primary metals; SIC 3441-fabricated structural metal; and SIC 373-ship and boat building and repairing.

Category iii: Facilities classified as SIC 10-metal mining; SIC 12-coal mining; SIC 13-oil and gas extraction; and SIC 14-nonmetallic mineral mining.

Category iv: Hazardous waste treatment, storage, or disposal facilities.

Category v: Landfills, land application sites, and open dumps that receive or have received industrial wastes.

Category vi: Facilities classified as SIC 5015-used motor vehicle parts; and SIC 5093-automotive scrap and waste material recycling facilities.

Category vii: Steam electric power generating facilities.

Category viii: Facilities classified as SIC 40-railroad transportation; SIC 41-local passenger transportation; SIC 42-trucking and warehousing (except public warehousing and storage); SIC 43-U.S. Postal Service; SIC 44-water transportation; SIC 45-transportation by air; and SIC 5171-petroleum bulk storage stations and terminals.

Category ix: Sewage treatment works.

Category x: Construction activities except operations that result in the disturbance of less than five acres of total land area.

Category xi: Facilities classified as SIC 20-food and kindred products; SIC 21-tobacco products; SIC 22-textile mill products; SIC 23-apparel related products; SIC 2434-wood kitchen cabinets manufacturing; SIC 25-furniture and fixtures; SIC 265-paperboard containers and boxes; SIC 267-converted paper and paperboard products; SIC 27-printing, publishing, and allied industries; SIC 283-drugs; SIC 285-paints, varnishes, lacquer, enamels, and allied products; SIC 30-rubber and plastics; SIC 31-leather and leather products (except leather and tanning and finishing); SIC 323-glass products; SIC 34-fabricated metal products (except fabricated structural metal); SIC 35-industrial and commercial machinery and computer equipment; SIC 36-electronic and other electrical equipment and components; SIC 37-transportation equipment (except ship and boat building and repairing); SIC 38-measuring, analyzing, and controlling instruments; SIC 39-miscellaneous manufacturing industries; and SIC 4221-4225-public warehousing and storage.

Pretreatment Program

Another type of discharge that is regulated by the CWA is one that goes to a publicly owned treatment works (POTW). The national pretreatment program (CWA section 307(b)) controls the indirect discharge of pollutants to POTWs by "industrial users." Facilities regulated under section 307(b) must meet certain pretreatment standards. The goal of the pretreatment program is to protect municipal wastewater treatment plants from damage that may occur when hazardous, toxic, or other wastes are discharged into a sewer system and to protect the quality of sludge generated by these plants.

EPA has developed technology-based standards for industrial users of POTWs. Different standards apply to existing and new sources within each category. "Categorical" pretreatment standards applicable to an industry on a nationwide basis are developed by EPA. In addition, another kind of pretreatment standard, "local limits," are developed by the POTW in order to assist the POTW in achieving the effluent limitations in its NPDES permit.

Regardless of whether a state is authorized to implement either the NPDES or the pretreatment program, if it develops its own program, it may enforce requirements more stringent than federal standards.

Wetlands

Wetlands, commonly called swamps, marshes, fens, bogs, vernal pools, playas, and prairie potholes, are a subset of “waters of the United States,” as defined in Section 404 of the CWA. The placement of dredge and fill material into wetlands and other water bodies (i.e., waters of the United States) is regulated by the U.S. Army Corps of Engineers (Corps) under 33 CFR Part 328. The Corps regulates wetlands by administering the CWA Section 404 permit program for activities that impact wetlands. EPA’s authority under Section 404 includes veto power of Corps permits, authority to interpret statutory exemptions and jurisdiction, enforcement actions, and delegating the Section 404 program to the states.

EPA’s Office of Water, at (202) 260-5700, will direct callers with questions about the CWA to the appropriate EPA office. EPA also maintains a bibliographic database of Office of Water publications which can be accessed through the Ground Water and Drinking Water Resource Center, at (202) 260-7786.

Oil Pollution Prevention Regulation

Section 311(b) of the CWA prohibits the discharge of oil, in such quantities as may be harmful, into the navigable waters of the United States and adjoining shorelines. The EPA Discharge of Oil regulation, 40 CFR Part 110, provides information regarding these discharges. The Oil Pollution Prevention regulation, 40 CFR Part 112, under the authority of Section 311(j) of the CWA, requires regulated facilities to prepare and implement Spill Prevention Control and Countermeasure (SPCC) plans. The intent of a SPCC plan is to prevent the discharge of oil from onshore and offshore non-transportation-related facilities. In 1990 Congress passed the Oil Pollution Act which amended Section 311(j) of the CWA to require facilities that because of their location could reasonably be expected to cause "substantial harm" to the environment by a discharge of oil to develop and implement Facility Response Plans (FRP). The intent of a FRP is to provide for planned responses to discharges of oil.

A facility is SPCC-regulated if the facility, due to its location, could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, and the facility meets one of the following criteria regarding oil storage: (1) the capacity of any aboveground storage tank exceeds 660 gallons, or (2) the total aboveground storage capacity exceeds 1,320 gallons, or (3) the underground storage capacity exceeds 42,000 gallons. 40 CFR Part 112.7 contains the format and content requirements for a SPCC plan. In New Jersey, SPCC plans can be combined with DPCC plans, required by the state, provided there is an appropriate cross-reference index to the requirements of both regulations at the front of the plan.

According to the FRP regulation, a facility can cause "substantial harm" if it meets one of the following criteria: (1) the facility has a total oil storage capacity greater than or equal to 42,000 gallons and transfers oil over water to or from vessels; or (2) the facility has a total oil storage capacity greater than or equal to 1 million gallons and meets any one of the following conditions: (i) does not have adequate secondary containment, (ii) a discharge could cause "injury" to fish and wildlife and sensitive environments, (iii) shut down a public drinking water intake, or (iv) has had a reportable oil spill greater than or equal to 10,000 gallons in the past 5 years. Appendix F of 40 CFR Part 112 contains the format and content requirements for a FRP. FRPs that meet EPA's requirements can be combined with U.S. Coast Guard FRPs or other contingency plans, provided there is an appropriate cross-reference index to the requirements of all applicable regulations at the front of the plan.

For additional information regarding SPCC plans, contact EPA's RCRA, Superfund, and EPCRA Hotline, at (800) 424-9346. Additional documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) mandates that EPA establish regulations to protect human health from contaminants in drinking water. The law authorizes EPA to develop national drinking water standards and to create a joint federal-state system to ensure compliance with these standards. The SDWA also directs EPA to protect underground sources of drinking water through the control of underground injection of fluid wastes.

EPA has developed primary and secondary drinking water standards under its SDWA authority. EPA and authorized states enforce the primary drinking water standards, which are contaminant-specific concentration limits that apply to certain public drinking water supplies. Primary drinking water standards consist of maximum contaminant level goals (MCLGs), which are non-enforceable health-based goals, and maximum contaminant levels (MCLs), which are enforceable limits set generally as close to MCLGs as possible, considering cost and feasibility of attainment.

Part C of the SDWA mandates EPA to protect underground sources of drinking water from inadequate injection practices. EPA has published regulations codified in 40 CFR Parts 144 to 148 to comply with this mandate. The Underground Injection Control (UIC) regulations break down injection wells into five different types, depending on the fluid injected and the formation that receives it. The regulations also include construction, monitoring, testing, and operating requirements for injection well operators. All injection wells have to be authorized by permit or by rule depending on their potential to threaten Underground Sources of Drinking Water (USDW). RCRA also regulates hazardous waste injection wells and a UIC permit is considered to meet the requirements of a RCRA permit. EPA has authorized delegation of the UIC for all wells in 35 states, implements the program in 10 states and all Indian lands, and shares responsibility with 5 states.

The SDWA also provides for a federally-implemented Sole Source Aquifer program, which prohibits federal funds from being expended on projects that may contaminate the sole or principal source of drinking water for a given area, and for a state-implemented Wellhead Protection program, designed to protect drinking water wells and drinking water recharge areas.

The SDWA Amendments of 1996 require states to develop and implement source water assessment programs (SWAPs) to analyze existing and potential threats to the quality of the public drinking water throughout the state. Every state is required to submit a program to EPA and to complete all assessments within 3 ½ years of EPA approval of the program. SWAPs include: (1) delineating the source water protection area, (2) conducting a contaminant source inventory, (3) determining the susceptibility of the public water supply to contamination from the inventories sources, and (4) releasing the results of the assessments to the public.

EPA's Safe Drinking Water Hotline, at (800) 426-4791, answers questions and distributes guidance pertaining to SDWA standards. The Hotline operates from 9:00 a.m. through 5:30 p.m., EST, excluding federal holidays. Visit the website at www.epa.gov/ogwdw for additional material.

Resource Conservation and Recovery Act

The Solid Waste Disposal Act (SWDA), as amended by the Resource Conservation and Recovery Act (RCRA) of 1976, addresses solid and hazardous waste management activities. The Act is commonly referred to as RCRA. The Hazardous and Solid Waste Amendments (HSWA) of 1984 strengthened RCRA's waste management provisions and added Subtitle I, which governs underground storage tanks (USTs).

Regulations promulgated pursuant to Subtitle C of RCRA (40 CFR Parts 260-299) establish a "cradle-to-grave" system governing hazardous waste from the point of generation to disposal. RCRA hazardous wastes include the specific materials listed in the regulations (discarded commercial chemical products, designated with the code "P" or "U"; hazardous wastes from specific industries/sources, designated with the code "K"; or hazardous wastes from non-specific sources, designated with the code "F") or materials which exhibit a hazardous waste characteristic (ignitability, corrosivity, reactivity, or toxicity and designated with the code "D").

Entities that generate hazardous waste are subject to waste accumulation, manifesting, and recordkeeping standards. A hazardous waste facility may accumulate hazardous waste for up to 90 days (or 180 days depending on the amount generated per month) without a permit or interim status. Generators may also treat hazardous waste in accumulation tanks or containers (in accordance with the requirements of 40 CFR Part 262.34) without a permit or interim status. Facilities that treat, store, or dispose of hazardous waste are generally required to obtain a RCRA permit.

Subtitle C permits are required for treatment, storage, or disposal facilities. These permits contain general facility standards such as contingency plans, emergency procedures, recordkeeping and reporting requirements, financial assurance mechanisms, and unit-specific standards. RCRA also contains provisions (40 CFR Subparts I and S) for conducting corrective actions which govern the cleanup of releases of hazardous waste or constituents from solid waste management units at RCRA treatment, storage, or disposal facilities.

Although RCRA is a federal statute, many states implement the RCRA program. Currently, EPA has delegated its authority to implement various provisions of RCRA to 47 of the 50 states and two U.S. territories. Delegation has not been given to Alaska, Hawaii, or Iowa.

Most RCRA requirements are not industry specific but apply to any company that generates, transports, treats, stores, or disposes of hazardous waste. Here are some important RCRA regulatory requirements:

- **Criteria for Classification of Solid Waste Disposal Facilities and Practices** (40 CFR Part 257) establishes the criteria for determining which solid waste disposal facilities and practices pose a reasonable probability of adverse effects on health or the environment. The criteria were adopted to ensure non-municipal, non-hazardous waste disposal units that receive conditionally exempt small quantity generator waste do not present risks to human health and environment.

- **Criteria for Municipal Solid Waste Landfills** (40 CFR Part 258) establishes minimum national criteria for all municipal solid waste landfill units, including those that are used to dispose of sewage sludge.

- **Identification of Solid and Hazardous Wastes** (40 CFR Part 261) establishes the standard to determine whether the material in question is considered a solid waste and, if so, whether it is a hazardous waste or is exempted from regulation.

- **Standards for Generators of Hazardous Waste** (40 CFR Part 262) establishes the responsibilities of hazardous waste generators including obtaining an EPA identification number, preparing a manifest, ensuring proper packaging and labeling, meeting standards for waste accumulation units, and recordkeeping and reporting requirements. Generators can accumulate hazardous waste on-site for up to 90 days (or 180 days depending on the amount of waste generated) without obtaining a permit.

- **Land Disposal Restrictions** (LDRs) (40 CFR Part 268) are regulations prohibiting the disposal of hazardous waste on land without prior treatment. Under the LDRs program, materials must meet treatment standards prior to placement in a RCRA land disposal unit (landfill, land treatment unit, waste pile, or surface impoundment). Generators of waste subject to the LDRs must provide notification of such to the designated TSD facility to ensure proper treatment prior to disposal.

- **Used Oil Management Standards** (40 CFR Part 279) impose management requirements affecting the storage, transportation, burning, processing, and re-refining of the used oil. For parties that merely generate used oil, regulations establish storage standards. For a party considered a used oil processor, re-refiner, burner, or marketer (one who generates and sells off-specification used oil directly to a used oil burner), additional tracking and paperwork requirements must be satisfied.

- RCRA contains unit-specific standards for all units used to store, treat, or dispose of hazardous waste, including **Tanks and Containers**. Tanks and containers used to store hazardous waste with a high volatile organic concentration must meet emission standards under RCRA. Regulations (40 CFR Part 264-265, Subpart CC) require generators to test the waste to determine the concentration of the waste, to satisfy tank and container emissions standards, and to inspect and monitor regulated units. These regulations apply to all facilities who store such waste, including large quantity generators accumulating waste prior to shipment offsite.

- **Underground Storage Tanks** (USTs) containing petroleum products (including gasoline, diesel, and used oil) and hazardous substances are regulated under Subtitle I of RCRA. Subtitle I regulations (40 CFR Part 280) contain tank design and release detection requirements, as well as financial responsibility and corrective action standards for USTs. The UST program also includes upgrade requirements for existing tanks that were to be met by December 22, 1998.

- **Boilers and Industrial Furnaces** (BIFs) that use or burn fuel containing hazardous waste must comply with design and operating standards. BIF regulations (40 CFR Part 266, Subpart H) address unit design, provide performance standards, require emissions monitoring, and, in some cases, restrict the type of waste that may be burned.

EPA's RCRA, Superfund, and EPCRA Hotline, at (800) 424-9346, responds to questions and distributes guidance regarding all RCRA regulations. Additional documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The RCRA Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), a 1980 law commonly known as Superfund, authorizes EPA to respond to releases, or threatened releases, of hazardous substances that may endanger public health, welfare, or the environment. CERCLA also enables EPA to force parties responsible for environmental contamination to clean it up or to reimburse the Superfund for response or remediation costs incurred by EPA. The Superfund Amendments and Reauthorization Act

(SARA) of 1986 revised various sections of CERCLA, extended the taxing authority for the Superfund, and created a free-standing law, SARA Title III, also known as the Emergency Planning and Community Right-to-Know Act (EPCRA).

The CERCLA hazardous substance release reporting regulations (40 CFR Part 302) direct the person in charge of a facility to report to the National Response Center (NRC) any environmental release of a hazardous substance which equals or exceeds a reportable quantity. Reportable quantities are listed in 40 CFR Part 302.4. A release report may trigger a response by EPA or by one or more federal or state emergency response authorities.

EPA implements hazardous substance responses according to procedures outlined in the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) (40 CFR Part 300). The NCP includes provisions for cleanups. The National Priorities List (NPL) currently includes approximately 1,300 sites. Both EPA and states can act at other sites; however, EPA provides responsible parties the opportunity to conduct cleanups and encourages community involvement throughout the Superfund response process.

EPA's RCRA, Superfund and EPCRA Hotline, at (800) 424-9346, answers questions and references guidance pertaining to the Superfund program. Documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The Superfund Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Emergency Planning And Community Right-To-Know Act

The Superfund Amendments and Reauthorization Act (SARA) of 1986 created the Emergency Planning and Community Right-to-Know Act (EPCRA, also known as SARA Title III), a statute designed to improve community access to information about chemical hazards and to facilitate the development of chemical emergency response plans by state and local governments. Under EPCRA, states establish State Emergency Response Commissions (SERCs), responsible for coordinating certain emergency response activities and for appointing Local Emergency Planning Committees (LEPCs).

EPCRA and the EPCRA regulations (40 CFR Parts 350-372) establish four types of reporting obligations for facilities which store or manage specified chemicals:

- **EPCRA section 302** requires facilities to notify the SERC and LEPC of the presence of any extremely hazardous substance at the facility in an amount in excess of the established threshold planning quantity.

The list of extremely hazardous substances and their threshold planning quantities is found at 40 CFR Part 355, Appendices A and B.

- **EPCRA section 303** requires that each LEPC develop an emergency plan. The plan must contain (but is not limited to) the identification of facilities within the planning district, likely routes for transporting extremely hazardous substances, a description of the methods and procedures to be followed by facility owners and operators, and the designation of community and facility emergency response coordinators.

- **EPCRA section 304** requires the facility to notify the SERC and the LEPC in the event of a release exceeding the reportable quantity of a CERCLA hazardous substance (defined at 40 CFR Part 302) or an EPCRA extremely hazardous substance.

- **EPCRA sections 311 and 312** require a facility at which a hazardous chemical, as defined by the Occupational Safety and Health Act, is present in an amount exceeding a specified threshold to submit to the SERC, LEPC and local fire department material safety data sheets (MSDSs) or lists of MSDSs and hazardous chemical inventory forms (also known as Tier I and II forms). This information helps the local government respond in the event of a spill or release of the chemical.

- **EPCRA section 313** requires certain covered facilities, including SIC codes 20 through 39 and, the seven industry groups added in 1997 (including metal mining (SIC code 10, except for SIC codes 1011, 1081, and 1094), coal mining (SIC code 12, except for SIC code 1241 and extraction activities), electrical utilities that combust coal and/or oil (SIC codes 4911, 4931, and 4939), RCRA Subtitle C hazardous waste treatment and disposal facilities (SIC code 4953), chemicals and allied products wholesale distributors (SIC code 5169), petroleum bulk plants and terminals (SIC code 5171), and solvent recovery services (SIC code 7389)), which have ten or more employees, and which manufacture, process, or use specified chemicals in amounts greater than threshold quantities, to submit an annual toxic chemical release report. This report, commonly known as the Form R, covers releases and transfers of toxic chemicals to various facilities and environmental media. EPA maintains the data reported in a publically accessible database known as the Toxics Release Inventory (TRI).

All information submitted pursuant to EPCRA regulations is publicly accessible, unless protected by a trade secret claim.

EPA's RCRA, Superfund and EPCRA Hotline, at (800) 535-0202, answers questions and distributes guidance regarding the emergency planning and community right-to-know regulations. Documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The EPCRA Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Clean Air Act

The Clean Air Act (CAA) and its amendments are designed to "protect and enhance the nation's air resources so as to promote the public health and welfare and the productive capacity of the population." The CAA consists of six sections, known as Titles, which direct EPA to establish national standards for ambient air quality and for EPA and the states to implement, maintain, and enforce these standards through a variety of mechanisms. Under the CAA, many facilities are required to obtain operating permits that consolidate their air emission requirements. State and local governments oversee, manage, and enforce many of the requirements of the CAA. CAA regulations appear at 40 CFR Parts 50-99.

Pursuant to Title I of the CAA, EPA has established national ambient air quality standards (NAAQSs) to limit levels of "criteria pollutants," including carbon monoxide, lead, nitrogen dioxide, particulate matter, ozone, and sulfur dioxide. Geographic areas that meet NAAQSs for a given pollutant are designated as attainment areas; those that do not meet NAAQSs are designated as non-attainment areas. Under section110 and other provisions of the CAA, each state must develop a State Implementation Plan (SIP) to identify sources of air pollution and to determine what reductions are required to meet federal air quality standards. Revised NAAQSs for particulates and ozone were proposed in 1996 and will become effective in 2001.

Title I also authorizes EPA to establish New Source Performance Standards (NSPS), which are nationally uniform emission standards for new and modified stationary sources falling within particular industrial categories. NSPSs are based on the pollution control technology available to that category of industrial source (see 40 CFR Part 60).

Under Title I, EPA establishes and enforces National Emission Standards for Hazardous Air Pollutants (NESHAPs), nationally uniform standards oriented toward controlling specific hazardous air pollutants (HAPs). Section 112(c) of the CAA further directs EPA to develop a list of sources that emit any of 188 HAPs, and to develop regulations for these categories of sources. To date EPA has listed 185 source categories and developed a schedule for the establishment of emission standards. The emission standards are being developed for both new and existing sources based on "maximum achievable control technology" (MACT). The MACT is defined as the control technology achieving the maximum degree of reduction in the emission of the HAPs, taking into account cost and other factors.

Title II of the CAA pertains to mobile sources, such as cars, trucks, buses, and planes. Reformulated gasoline, automobile pollution control devices, and vapor recovery nozzles on gas pumps are a few of the mechanisms EPA uses to regulate mobile air emission sources.

Title IV-A establishes a sulfur dioxide and nitrogen oxides emissions program designed to reduce the formation of acid rain. Reduction of sulfur dioxide releases will be obtained by granting to certain sources limited emissions allowances that are set below previous levels of sulfur dioxide releases.

Title V of the CAA establishes an operating permit program for all "major sources" (and certain other sources) regulated under the CAA. One purpose of the operating permit is to include in a single document all air emissions requirements that apply to a given facility. States have developed the permit programs in accordance with guidance and regulations from EPA. Once a state program is approved by EPA, permits are issued and monitored by that state.

Title VI is intended to protect stratospheric ozone by phasing out the manufacture of ozone-depleting chemicals and restricting their use and distribution. Production of Class I substances, including 15 kinds of chlorofluorocarbons (CFCs), were phased out (except for essential uses) in 1996.

EPA's Clean Air Technology Center, at (919) 541-0800 or www.epa.gov/ttn/catc, provides general assistance and information on CAA standards. The Stratospheric Ozone Information Hotline, at (800) 296-1996 or www.epa.gov/ozone, provides general information about regulations promulgated under Title VI of the CAA; EPA's EPCRA Hotline, at (800) 535-0202 or www.epa.gov/epaoswer/hotline, answers questions about accidental release prevention under CAA section112(r); and information on air toxics can be accessed through the Unified Air Toxics website at www.epa.gov/ttn/uatw. In addition, the Clean Air Technology Center's website includes recent CAA rules, EPA guidance documents, and updates of EPA activities.

Federal Insecticide, Fungicide, and Rodenticide Act

The Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) was first passed in 1947, and amended numerous times, most recently by the Food Quality Protection Act (FQPA) of 1996. FIFRA provides EPA with the authority to oversee, among other things, the registration, distribution, sale and use of pesticides. The Act applies to all types of pesticides, including insecticides, herbicides, fungicides, rodenticides and antimicrobials. FIFRA covers both intrastate and interstate commerce.

Establishment Registration

Section 7 of FIFRA requires that establishments producing pesticides, or active ingredients used in producing a pesticide subject to FIFRA, register with EPA. Registered establishments must report the types and amounts of pesticides and active ingredients they produce. The Act also provides EPA inspection authority and enables the agency to take enforcement actions against facilities that are not in compliance with FIFRA.

Product Registration

Under section 3 of FIFRA, all pesticides (with few exceptions) sold or distributed in the U.S. must be registered by EPA. Pesticide registration is very specific and generally allows use of the product only as specified on the label. Each registration specifies the use site i.e., where the product may be used and the amount that may be applied. The person who seeks to register the pesticide must file an application for registration. The application process often requires either the citation or submission of extensive environmental, health and safety data.

To register a pesticide, the EPA Administrator must make a number of findings, one of which is that the pesticide, when used in accordance with widespread and commonly recognized practice, will not generally cause unreasonable adverse effects on the environment.

FIFRA defines "unreasonable adverse effects on the environment" as "(1) any unreasonable risk to man or the environment, taking into account the economic, social, and environmental costs and benefits of the use of the pesticide, or (2) a human dietary risk from residues that result from a use of a pesticide in or on any food inconsistent with the standard under section 408 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 346a)."

Under FIFRA section 6(a)(2), after a pesticide is registered, the registrant must also notify EPA of any additional facts and information concerning unreasonable adverse environmental effects of the pesticide. Also, if EPA determines that additional data are needed to support a registered pesticide, registrants may be requested to provide additional data. If EPA determines that the registrant(s) did not comply with their request for more information, the registration can be suspended under FIFRA section 3(c)(2)(B).

Use Restrictions

As a part of the pesticide registration, EPA must classify the product for general use, restricted use, or general for some uses and restricted for others (Miller, 1993). For pesticides that may cause unreasonable adverse effects on the environment, including injury to the applicator, EPA may require that the pesticide be applied either by or under the direct supervision of a certified applicator.

Reregistration

Due to concerns that much of the safety data underlying pesticide registrations becomes outdated and inadequate, in addition to providing that registrations be reviewed every 15 years, FIFRA requires EPA to reregister all pesticides that were registered prior to 1984 (section 4). After reviewing existing data, EPA may approve the reregistration, request additional data to support the registration, cancel, or suspend the pesticide.

Tolerances and Exemptions

A tolerance is the maximum amount of pesticide residue that can be on a raw product and still be considered safe. Before EPA can register a pesticide that is used on raw agricultural products, it must grant a tolerance or exemption from a tolerance (40 CFR Parts 163.10 through 163.12). Under the Federal Food, Drug, and Cosmetic Act (FFDCA), a raw agricultural product is deemed unsafe if it contains a pesticide residue, unless the residue is within the limits of a tolerance established by EPA or is exempt from the requirement.

Cancellation and Suspension

EPA can cancel a registration if it is determined that the pesticide or its labeling does not comply with the requirements of FIFRA or causes unreasonable adverse effects on the environment (Haugrud, 1993).

In cases where EPA believes that an "imminent hazard" would exist if a pesticide were to continue to be used through the cancellation proceedings, EPA may suspend the pesticide registration through an order and thereby halt the sale, distribution, and usage of the pesticide. An "imminent hazard" is defined as an unreasonable adverse effect on the environment or an unreasonable hazard to the survival of a threatened or endangered species that would be the likely result of allowing continued use of a pesticide during a cancellation process.

When EPA believes an emergency exists that does not permit a hearing to be held prior to suspending, EPA can issue an emergency order which makes the suspension immediately effective.

Imports and Exports

Under FIFRA section 17(a), pesticides not registered in the U.S. and intended solely for export are not required to be registered provided that the exporter obtains and submits to EPA, prior to export, a statement from the foreign purchaser acknowledging that the purchaser is aware that the product is not registered in the United States and cannot be sold for use there. EPA sends these statements to the government of the importing country. FIFRA sets forth additional requirements that must be met by pesticides intended solely for export. The enforcement policy for exports is codified at 40 CFR Parts 168.65, 168.75, and 168.85.

Under FIFRA section 17(c), imported pesticides and devices must comply with U.S. pesticide law. Except where exempted by regulation or statute, imported pesticides must be registered. FIFRA section 17(c) requires that EPA be notified of the arrival of imported pesticides and devices. This is accomplished through the Notice of Arrival (NOA) (EPA Form 3540-1), which is filled out by the importer prior to importation and submitted to the EPA regional office applicable to the intended port of entry. U.S. Customs regulations prohibit the importation of pesticides without a completed NOA. The EPA-reviewed and signed form is returned to the importer for presentation to U.S. Customs when the shipment arrives in the U.S. NOA forms can be obtained from contacts in the EPA Regional Offices or *www.epa.gov/oppfead1/international/noalist.htm*.

Additional information on FIFRA and the regulation of pesticides can be obtained from a variety of sources, including EPA's Office of Pesticide Programs www.epa.gov/pesticides, EPA's Office of Compliance, Agriculture and Ecosystem Division es.epa.gov/oeca/agecodiv.htm, or The National Agriculture Compliance Assistance Center, (888) 663-2155 or es.epa.gov/oeca/ag. Other sources include the National Pesticide Telecommunications Network, (800) 858-7378, and the National Antimicrobial Information Network, (800) 447-6349.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) granted EPA authority to create a regulatory framework to collect data on chemicals in order to evaluate, assess, mitigate, and control risks which may be posed by their manufacture, processing, and use. TSCA provides a variety of control methods to prevent chemicals from posing unreasonable risk. It is important to note that pesticides as defined in FIFRA are not included in the definition of a "chemical substance" when manufactured, processed, or distributed in commerce for use as a pesticide.

TSCA standards may apply at any point during a chemical's life cycle. Under TSCA section 5, EPA has established an inventory of chemical substances. If a chemical is not already on the inventory, and has not been excluded by TSCA, a premanufacture notice (PMN) must be submitted to EPA prior to manufacture or import. The PMN must identify the chemical and provide available information on health and environmental effects. If available data are not sufficient to evaluate the chemical's effects, EPA can impose restrictions pending the development of information on its health and environmental effects. EPA can also restrict significant new uses of chemicals based upon factors such as the projected volume and use of the chemical.

Under TSCA section 6, EPA can ban the manufacture or distribution in commerce, limit the use, require labeling, or place other restrictions on chemicals that pose unreasonable risks. Among the chemicals EPA regulates under section 6 authority are asbestos, chlorofluorocarbons (CFCs), lead, and polychlorinated biphenyls (PCBs).

Under TSCA section 8(e), EPA requires the producers and importers (and others) of chemicals to report information on a chemicals' production, use, exposure, and risks. Companies producing and importing chemicals can be required to report unpublished health and safety studies on listed chemicals and to collect and record any allegations of adverse reactions or any information indicating that a substance may pose a substantial risk to humans or the environment.

EPA's TSCA Assistance Information Service, at (202) 554-1404, answers questions and distributes guidance pertaining to Toxic Substances Control Act standards. The Service operates from 8:30 a.m. through 4:30 p.m., EST, excluding federal holidays.

Coastal Zone Management Act

The Coastal Zone Management Act (CZMA) encourages states/tribes to preserve, protect, develop, and where possible, restore or enhance valuable natural coastal resources such as wetlands, floodplains, estuaries, beaches, dunes, barrier islands, and coral reefs, as well as the fish and wildlife using those habitats. It includes areas bordering the Atlantic, Pacific, and Arctic Oceans, Gulf of Mexico, Long Island Sound, and Great Lakes. A unique feature of this law is that participation by states/tribes is voluntary.

In the Coastal Zone Management Act Reauthorization Amendments (CZARA) of 1990, Congress identified nonpoint source pollution as a major factor in the continuing degradation of coastal waters. Congress also recognized that effective solutions to nonpoint source pollution could be implemented at the state/tribe and local levels. In CZARA, Congress added

Section 6217 (16 U.S.C. section 1455b), which calls upon states/tribes with federally-approved coastal zone management programs to develop and implement coastal nonpoint pollution control programs. The Section 6217 program is administered at the federal level jointly by EPA and the National Oceanic and Atmospheric Agency (NOAA).

Section 6217(g) called for EPA, in consultation with other agencies, to develop guidance on "management measures" for sources of nonpoint source pollution in coastal waters. Under Section 6217, EPA is responsible for developing technical guidance to assist states/tribes in designing coastal nonpoint pollution control programs. On January 19, 1993, EPA issued its *Guidance Specifying Management Measures For Sources of Nonpoint Pollution in Coastal Waters*, which addresses five major source categories of nonpoint pollution: (1) urban runoff, (2) agriculture runoff, (3) forestry runoff, (4) marinas and recreational boating, and (5) hydromodification.

Additional information on coastal zone management may be obtained from EPA's Office of Wetlands, Oceans, and Watersheds, www.epa.gov/owow, or from the Watershed Information Network www.epa.gov/win. The NOAA website, www.nos.noaa.gov/ocrm/czm/, also contains additional information on coastal zone management.

VI.B. Industry Specific Requirements

The onshore and offshore segments of the oil and gas extraction industry are subject to different sets of regulations. Onshore, releases primarily are under the authority of EPA. Federal land leases are managed by the Bureau of Land Management (BLM) in the Department of the Interior (DOI). States also impose regulations and play a crucial role in exploration and production solid waste regulation because of the RCRA exemption. Offshore, on the Outer Continental Shelf (OCS), the Minerals Management Service (MMS) of DOI is the designated regulatory agency. MMS oversees leasing operations and shares responsibility for environmental regulation with EPA.

Because of these differences, onshore and offshore regulations are discussed in separate sections. In addition, regulatory differences associated with stripper wells (wells that produce less than 10 barrels of oil per day) and selected state regulations are presented.

VI.B.1. Onshore Requirements

Laws Regulating Oil and Gas Exploration and Production on Federal Lands

Many regulations controlling the location of onshore oil and gas production stem from the Federal Land Policy and Management Act (FLPMA) of 1976. Production is barred at national monuments, national rivers, and areas of critical environmental concern. On Federal land where oil production is allowed, the Bureau of Land Management (BLM), under the Department of the Interior (DOI), is authorized under 43 CFR Parts 3160-92 to regulate the siting, drilling and production activities; an exception is on lands within the National Forest System, where BLM must obtain the consent of the Secretary of Agriculture. Oil and gas production regulation is achieved through the distribution of leases and the issuance of drilling permits. Most procedures are established under the Federal Oil and Gas Leasing Reform Act of 1987. Included in this Act are bonding regulations, presented in 43 CFR Part 3104, that require submission of a surety or personal bond to ensure compliance with requirements for the plugging of wells, reclamation of the leased areas, and restoration of any lands or surface waters adversely affected by lease operations. The BLM is revising its regulations. A proposed rule was promulgated in early 1999.

<u>National Environmental Policy Act (NEPA)</u>
NEPA requires that all Federal agencies prepare detailed statements assessing the environmental impact of, and alternatives to, major Federal actions that may “significantly affect” the environment. An environmental impact statement (EIS) must provide a fair and full discussion of significant environmental impacts and inform both decision-makers and the public about

the reasonable alternatives that would avoid or minimize adverse impacts on the environment; EISs must explore and evaluate all reasonable alternatives, even if they are not within the authority of the lead agency. NEPA authorities are solely procedural; NEPA cannot compel selection of the environmentally preferred alternative. For offshore operations new sources require NEPA analysis.

Federal actions specifically related to oil and gas exploration and production that may require EISs include Federal land management agency (e.g., BLM and Forest Service) approval of plans of operations for exploration or production on Federally-managed lands. All affected media (e.g., air, water, soil, geologic, cultural, economic resources, etc.) must be addressed. The EIS provides the basis for the permit decision; for example, an NPDES permit may be issued or denied based on EPA's review of the overall impacts, not just discharge-related impacts, of the proposed project and alternatives. Issues may include the potential for surface or groundwater contamination, aquatic and terrestrial habitat value and losses, sediment production, mitigation, and reclamation.

Clean Air Act (CAA)

The oil and gas production industry is subject to recently-promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) (Federal Register, Vol. 64, No. 116, June 17, 1999). The regulation calls for the application of maximum achievable control technology (MACT) in order to reduce the emissions of hazardous air pollutants (HAP) at facilities classified as major sources. The primary HAPs released by the industry are benzene, toluene, ethyl benzene, and mixed xylenes (BTEX) and n-heptane. The technology requirements involve the following emission points: process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks at natural gas processing plants. Additional requirements include the installation of air emission control devices, and adherence to test methods and procedures, monitoring and inspection requirements, and recordkeeping and reporting requirements.

In addition, New Source Performance Standards (NSPS) may affect exploration and production facilities. Standards apply to devices used at these facilities, including gas turbines, steam generators, storage vessels for petroleum liquids, volatile organic liquid storage vessels, and gas processing plants (see 40 CFR Part 60). Requirements will depend on whether the region in which the particular facility is located is in compliance with the National Ambient Air Quality Standards (NAAQS) and whether Prevention of Significant Deterioration (PSD) requirements apply (EPA, 1992).

Clean Water Act

Onshore exploration and production facilities may be subject to four aspects of the CWA: national effluent limitation guidelines, stormwater regulations, and wetlands regulations, and Spill Prevention Control and Countermeasure (SPCC) requirements.

National effluent limitation guidelines have been issued for two subcategories of onshore (non-stripper) wells. The Onshore Subcategory guidelines prohibit the discharge of water pollutants from any source associated with production, field exploration, drilling, well completion, or well treatment (40 CFR Part 435.30). Agriculture and Wildlife Water Use Subcategory guidelines apply to facilities in the continental United States west of the 98^{th} meridian for which produced water may be used beneficially for irrigation or wildlife propagation. For facilities in this subcategory, produced water may be discharged into navigable waters so long as it does not exceed limitations for oil and grease, and is put to use for agricultural purposes. Discharge of waste pollutants excluding produced water is prohibited (40 CFR Part 435.50).

Oil and gas exploration and production facilities are exempt from CWA stormwater Phase I regulations under most conditions, but there are two exceptions: (1) if the facility has a reportable quantity spill that could be carried to waters of the United States via a storm event, or (2) if the stormwater runoff violates a water quality standard. (See 40 CFR Parts 117 and/or 302 for reportable quantities of hazardous substances or Part 110 for the reportable quantity of spilled oil.) If either of these two scenarios should happen, the facility would be required to apply for a Multi-Sector General Permit (MSGP) stormwater permit and develop a pollution prevention plan. However, if a reportable quantity spill were to be cleaned up quickly or containment were so total that there would be no threat of a product release as a result of storm water event, there would be no permit requirement. In addition, coverage is mandatory under the Construction General Permit (CGP) for earth-disturbing activities of five acres or more. This is relevant during exploration or site expansion efforts (EPA Region VI Stormwater Hotline, 1999; Rittenhouse, 1999). See Section VI.C. for proposed Phase II regulations that may impact the industry.

<u>Wetlands</u>
During the course of petroleum exploration wetlands may be encountered. Under the CWA wetlands are defined by the frequency and length of time they are saturated with water, by the type of vegetation they support, and by soil characteristics. Also by definition wetlands are part of the "waters of the United States" and as such all discharges of pollutants to wetlands require a CWA permit. However, the CWA regulates not only the discharges of dissolved pollutants but also the discharge of solids, dredge and fill materials

or dirt to waters of the United States. Permits are required for the filling of wetlands (dredging is regulated under the 1899 Rivers and Harbors Act). Permits are of two types: general (a standard permit for certain classes of activities) or site-specific.

Enforcement of the CWA provisions for wetlands is overseen by the Army Corps of Engineers, EPA and in some cases the States. Most of the day to day administration of the program is implemented by the Corps of Engineers (COE). The COE issues and enforces permits, and is also responsible for delineating wetlands. EPA regions comment on permits and can enforce the provisions of the Act. EPA also helps to develop environmental criteria for wetlands. The COE can approve a state to operate the CWA wetlands program (only Maryland and New Jersey are currently approved). If a state is authorized to operate the CWA wetlands program it may issue a permit in addition to the COE issued permit. Any state can comment on wetland permits prior to issuance.

<u>Spill Prevention Control and Countermeasure Plans</u>
An oil and gas production, drilling, or workover facility will be subject to Spill Prevention Control and Countermeasure (SPCC) requirements if it meets the following specifications: the facility could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, and have (1) a total underground buried storage capacity of more than 42,000 gallons; (2) a total aboveground oil storage capacity of more than 1,320 gallons; or (3) an aboveground oil storage capacity of more than 660 gallons in a single container. SPCC applicability is dependent on the tank's maximum design storage volume and not "safe" operating or other lesser operational volumes. For purposes of the regulation, an onshore production facility may include all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator.

All facilities subject to SPCC requirements must prepare a site-specific spill prevention plan that incorporates requirements specified in 40 CFR Part 112.7. For production facilities, these include considerations for the following processes and procedures:

- Drainage
- Tank materials
- Secondary containment
- Visual inspection of tanks
- Fail-safe engineering methods for tank battery installations
- Tank repair and maintenance
- Facility transfer operations

- Inspection and testing measures
- Record-keeping
- Security
- Personnel training.

In addition, the plan must discuss spill history and spill prediction (i.e., the anticipated direction of flow). The SPCC plan must be approved by a Registered Professional Engineer who is familiar with SPCC requirements, be fully implemented, and be modified when changes are made to the facility (e.g., installation of a new tank). Regardless of whether changes have been made to the facility, the plan must be reviewed at least once every three years, and amended if new, field-proven technology may reduce the likelihood of a spill.

The SPCC plan must also address oil drilling and workover facility equipment. This portion of the plan requires that the equipment be positioned or located so as to prevent spilled oil from reaching navigable waters, that catchment basins or diversionary structures be in place, and that blowout preventers (BOPs) are installed according to state regulatory requirements.

A portion of SPCC-regulated facilities may also be subject to Facility Response Planning (FRP) requirements if they pose a threat of "substantial harm" to navigable waters. The determination of a "substantial harm" facility is made on the basis of meeting either of two sets of criteria – one involving transfer over water, and the other involving oil storage capacity or other factors. If the facility were subject to FRP requirements, it would be required to develop a facility response plan which would involve, among other requirements, identification of small, medium and worst-case discharge scenarios and response actions; a description of discharge detection procedures and equipment; detailed implementation plans for containment and disposal; diagrams of facility and surrounding layout, topography, and evacuation paths; and employee training, exercises, and drills.

Safe Drinking Water Act (SDWA)

The Underground Injection Control (UIC) program of the SDWA regulates injection wells used in the oil and gas production process for produced water disposal or for enhanced recovery. Wells used in this industry for produced water are classified as Class II. Minimum UIC Class II well requirements, as outlined in 40 CFR Part 144, involve specific construction, operation, and closure standards, as well as provisions for ensuring that the owner, operator and/or transferor of the well maintain financial responsibility and resources to plug and abandon the well. Included are casing and cementing requirements based on the depth to the injection zone, location of aquifers, and estimated injection pressures as well as other possible considerations. Operational standards involve regular (at least once every five years) mechanical integrity tests (MITs); monitoring of injection pressure, flow rate, and volume; monitoring of the nature of injected fluid as needed; and annual reporting of monitoring results. Finally, closure procedures must be performed in accordance with an approved plugging and abandonment plan, which includes the placement and composition of cement plugs, the amount of casing to be left in the hole, the estimated cost of plugging, and any proposed tests or measurements. Additional requirements may be imposed in states that have been delegated implementation of the UIC program.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

The "petroleum exclusion" is an important exemption under CERCLA requirements for the oil and gas extraction industry. Under the "hazardous substance" definition, "petroleum, including crude oil or any fraction thereof," is exempted unless specifically listed or designated under CERCLA (CERCLA section 101 (14)). Subsequent interpretation has concluded that listed hazardous substances that are normally found in crude oil, such as benzene, do not invalidate the exemption unless the concentration of these substances is increased by contamination or by addition after refining. However, specifically listed waste oils (e.g., F010, and K042 through K048) are subject to reporting requirements if spilled in excess of their established Reportable Quantities (RQs) (EPA, 1998).

Emergency Planning and Community Right-to-Know Act (EPCRA)

The oil and gas extraction industry is currently not required to report to TRI under EPCRA section 313, which requires facilities under certain SIC codes to submit annual reports of toxic chemical releases to the Toxic Release Inventory (TRI). (Please see Section VI.C., Pending and Proposed Regulatory Requirements, of this document, however, for possible future changes to this status.) However, oil and gas extraction facilities are generally responsible for other reporting obligations of EPCRA if the facility stores or manages threshold levels of specified chemicals.

Resource Conservation and Recovery Act (RCRA)

Under the 1980 Amendments to RCRA, Congress conditionally exempted certain categories of solid waste from regulation as hazardous wastes under RCRA Subtitle C including drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas. The Amendments required EPA to study these wastes to determine whether their regulation as hazardous wastes was warranted and to submit a report to Congress. In its report to Congress and in a July 1988 regulatory determination (53 FR 25446, July 6, 1988), the Agency stated that regulation as hazardous wastes under Subtitle C was not warranted and that these wastes could be controlled under other federal and state regulatory programs including a tailored RCRA Subtitle D program.

Specifically, EPA's regulatory determination for exploration and production (E&P) wastes found that the following wastes are exempt from RCRA hazardous waste management requirements. The list below identifies many, but not all, exempt wastes. In general, E&P exempt wastes are generated in "primary field operations," and not as a result of maintenance or transportation activities. Exempt wastes are typically limited to those that are intrinsically related to the production of oil or natural gas.

- Produced water;
- Drilling fluids;
- Drill cuttings;
- Rigwash;
- Drilling fluids and cuttings from offshore operations disposed of onshore;
- Well completion, treatment, and stimulation fluids;
- Basic sediment and water, and other tank bottoms from storage facilities that hold product and exempt waste;
- Accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments;
- Pit sludges and contaminated bottoms from storage or disposal of exempt wastes;
- Workover wastes;
- Gas plant sweetening wastes for sulfur removal, including amine, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge;
- Cooling tower blowdown;
- Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream);
- Packing fluids;
- Produced sand;
- Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation;
- Hydrocarbon-bearing soil;
- Pigging wastes from gathering lines;
- Wastes from subsurface gas storage and retrieval, except for the listed non-exempt wastes;
- Constituents removed from produced water before it is injected or otherwise disposed of;
- Liquid hydrocarbons removed from the production stream but not from oil refining;

- Gases removed from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons;
- Materials ejected from a producing well during the process known as blowdown;
- Waste crude oil from primary field operations and production; and
- Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment.

On March 22, 1993, EPA provided "clarification" regarding the scope of the E&P waste exemption for waste streams generated by crude oil and tank bottom reclaimers, oil and gas service companies, crude oil pipelines, and gas processing plants and their associated field gathering lines. (See 58 FR 15284-15287.) EPA stated that certain waste streams from these operations are "uniquely associated" with primary field operations and as such are within the scope of the RCRA Subtitle C exemption. EPA's clarification cautioned, however, that these wastes may not be exempt if they are mixed with non-exempt materials or wastes.

EPA's 1988 regulatory determination lists the following wastes as non-exempt. The list below identifies many, but not all non-exempt wastes, as well as transportation (pipeline and trucking) activities. While the following wastes are non-exempt, their regulatory status as "hazardous wastes" is dependent upon a determination of their characteristics or whether they are specifically listed as RCRA hazardous waste.

- Unused fracturing fluids or acids;
- Gas plant cooling tower cleaning wastes;
- Painting wastes;
- Oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids;
- Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste;
- Refinery wastes;
- Liquid and solid wastes generated by crude oil and tank bottom reclaimers;
- Used equipment lubrication oils;
- Waste compressor oil, filters, and blowdown;
- Used hydraulic fluids;
- Waste solvents;
- Waste in transportation pipeline-related pits;
- Caustic or acid cleaners;
- Boiler cleaning wastes;
- Boiler refractory bricks;
- Incinerator ash;

- Laboratory wastes;
- Sanitary wastes;
- Pesticide wastes;
- Radioactive tracer wastes; and
- Drums, insulation, and miscellaneous solids.

EPA did not specifically address, in its 1988 regulatory determination, the status of hydrocarbon-bearing material that is recycled or reclaimed by reinjection into a crude stream. However, under existing EPA regulations, recycled oil, even if it were otherwise hazardous, could be reintroduced into the crude stream, if it is from normal operations and is to be refined along with normal process streams at a petroleum refinery facility (40 CFR Part 261.6 (a)(3)(vi).)

The Agency also determined that produced water injected for enhanced recovery is not a waste for purposes of RCRA regulation and therefore is not subject to control under RCRA Subtitle C or Subtitle D. Produced water used in this manner is considered beneficially recycled and is an integral part of some crude oil and natural gas production processes. Produced water injected in this manner is already regulated by the Underground Injection Control program under the SDWA. However, if produced water is stored in surface impoundments prior to injection, it may be subject to RCRA Subtitle D regulations.

It is important to note that some states have adopted hazardous waste regulations which differ from those that EPA has promulgated. While different in many specific areas, those state programs, by law, still must be at least as stringent as the federal programs.

Endangered Species Act (ESA)

The ESA provides a means to protect threatened or endangered species and the ecosystems that support them. It requires Federal agencies to ensure that activities undertaken on either Federal or non-Federal property do not have adverse impacts on threatened or endangered species or their habitat. In a 1995 ruling, the U.S. Supreme Court upheld interpretations of the Act that allow agencies to consider impact on habitat as a potential form of prohibited "harm" to endangered species. Agencies undertaking a Federal action (such as a BLM or MMS review of proposed oil and gas extraction production operations) must consult with the U.S. Fish and Wildlife Service, and an EIS must be prepared if "any major part of a new source will have significant adverse effect on the habitat" of a Federally- or State-listed threatened or endangered species.

VI.B.2. Offshore Requirements

This section describes laws and regulations applying to offshore production facilities that differ from those presented above for onshore facilities. It should be noted that several regulations presented in the onshore section will apply to offshore sites as well. Offshore facilities are: 1) those which are found within the Federal jurisdiction of the Outer Continental Shelf and are operated under Minerals Management Service (MMS) leases, and 2) those that are found in territorial seas and are operated under state leases. Facilities in the territorial seas are operated under both state and federal regulations and therefore some regulations discussed below may not be applicable. In addition, coastal facilities, which are generally landward of the inner boundary of the territorial seas (approximated by the shoreline) are operated under state regulations and therefore some regulations discussed below may not be applicable.

Offshore Jurisdictions

The Outer Continental Shelf (OCS) consists of the submerged lands, subsoil, and seabed, lying between the seaward extent of the states' jurisdiction and the seaward extent of federal jurisdiction. The continental shelf is the gently sloping undersea plain between a continent and the deep ocean. The United States OCS has been divided into four leasing regions. They are the Gulf of Mexico Region, the Atlantic OCS Region, the Pacific OCS Region, and the Alaska OCS Region. State jurisdiction is defined as follows. Texas and the Gulf Coast of Florida are extended 3 marine leagues (approximately 9 nautical miles) seaward from the baseline from which the breadth of the territorial sea is measured. Louisiana is extended 3 imperial nautical miles (imperial nautical miles are 6,080.2 feet) seaward of the baseline from which the breadth of the territorial sea is measured. All other states' seaward limits are extended 3 nautical miles (approximately 3.3 statute miles) seaward of the baseline from which the breadth of the territorial sea is measured. Federal jurisdiction is defined under accepted principals of international law. The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured.

Outer Continental Shelf Lands Act (OSCLA)

OCSLA establishes Federal jurisdiction over submerged lands on the Outer Continental Shelf (OCS) and requires the Secretary of the Interior to administer mineral leasing, exploration, and development on the OCS. Under the Act, leases are granted to the highest qualified responsible bidder(s), on the basis of sealed competitive bids. Objectives of the OCSLA include allowing for expeditious and orderly development of OCS resources, encouraging the development of new technology to minimize the likelihood of accidents or events that might damage the environment or endanger life or health, and ensuring that a State's regulatory protection for land, air, and water uses are considered within its jurisdiction (MMS, 1999; National Research Council, 1996).

In offshore locations, the production is limited under Title III of the Marine Protection, Research, and Sanctuaries Act (MPRSA), which provides for the designation of sanctuaries for areas of conservation, recreational, ecological, or aesthetic value. The Marine Mammal Protection Act (MMPA) and the Endangered Species Act (ESA) prohibit the taking of species, and can also limit the placement of offshore wells.

Clean Air Act

In offshore areas, both the CAA and regulations of the MMS govern air quality. Coastal areas and the offshore regions of the Pacific, Atlantic, and Arctic Oceans, as well as the region of the Gulf of Mexico adjacent to Florida, are subject to the CAA. Important regulations include the NESHAP and NSPS standards described above for onshore facilities.

The sections of the Gulf of Mexico adjacent to Texas, Louisiana, Mississippi, and Alabama are exempt from the 1990 CAA amendments, and instead must adhere to MMS air quality standards. These standards set limits for VOC, CO, NO_2, SO_2, and Total Suspended Particulate (TSP) pollutants, and require limits for sources that significantly affect the quality of a nonattainment area (30 CFR Part 250.45).

Additional MMS air regulations apply to offshore sites. Blowout prevention regulations (in the form of safety practices and equipment requirements) attempt to reduce accidental releases. The venting and flaring of natural gas is limited under MMS rules so that natural gas may be released only when required for safety or when the volume is small (Sustainable Environmental Law and 30 CFR Part 250.175).

Clean Water Act

In offshore locations, facilities must acquire National Pollutant Discharge Elimination System (NPDES) permits before any pollutant can be discharged from a point source in U.S. waters. Standards differ for the offshore and coastal subcategories. For offshore facilities, permits require the use of best available technology economically achievable (BAT) or best conventional pollutant control technology (BCT). Discharges from coastal facilities, which are landward of the inner boundary of the territorial seas, are mostly prohibited (Jordan, 1998; note that the definition of the coastal category for the purposes of the CWA is different than that for mineral rights, presented in Section II). An exception to the coastal discharge prohibition is for facilities in Cook Inlet, Alaska, where discharges may be made in accordance with BPT, BAT, or BCT effluent limitations.

Facilities located offshore of EPA Region 6 (and some in Regions 9 and 10) are subject to a general CWA permit that covers all facilities in certain geographic locations. Offshore exploration and production facilities in Regions 4, 9 and 10 are also permitted individually in some cases. EPA Regions 6 and 9 have an MOA with MMS whereby MMS agrees to conduct CWA preliminary inspections for EPA.

In addition to NPDES permitting requirements, offshore facilities may be subject to CWA Section 403. This section is intended to ensure that no unreasonable degradation of the marine environment occurs as a result of permitted discharges, and to ensure that sensitive ecological communities are protected. Requirements may involve ambient monitoring programs to determine degradation of marine waters, alternative assessments designed to further evaluate the consequences of various disposal options, and pollution prevention techniques designed to further reduce the quantities of pollutants requiring disposal and thereby reduce the potential for harm to the marine environment. If section 403 requirements for protection of the ecological health of marine waters are not met, an NPDES permit will not be issued.

Spill Prevention Control and Countermeasure Plans

Many aspects of SPCC rule described above for onshore facilities apply to offshore facilities as well. 40 CFR Part 112.7(e)(7) provides additional spill prevention and control measures to be addressed in SPCC plans for offshore facilities. These include:

- Oil drainage collection equipment around pumps, joints, valves, separators, tanks, etc.
- Adequately-sized sump systems
- Dump valves installed with oil-water separators and treaters
- High-level sensing devices for atmospheric storage tanks and corrosion protection for all tanks
- High pressure sensing device and shut-in valve for pipelines appurtenant to the facility.

Oil Spill Contingency Plans

Pursuant to 30 CFR 250.203, 250.204 and 254, a lessee is required to submit an Oil Spill Contingency Plan (OSCP) to MMS for approval. This plan identifies the response capabilities of lease and pipeline operators in the event an accidental oil spill occurs during drilling or production activities.

Additionally, the Oil Pollution Act of 1990 authorizes the MMS to require Oil Spill Contingency Plans from oil and gas lessees operating in state waters seaward of the coastline. Operators must join a cooperative with oil spill equipment available to members, or obtain a letter of agreement for rental of oil spill equipment. Oil Spill Coordinators must be trained. The entire Oil Spill Response Team must attend annual drills. The Plan requires annual review and update.

VI.B.3. Stripper Well Requirements

Stripper wells are identified as an individual subcategory in Clean Water Act NPDES requirements. In addition, stripper wells may be exempt from requirements under other statutes or regulations by virtue of their low production volume. For example, they may not meet the threshold of a major source of HAP for NESHAP requirements, or they may have less than the specified storage volume for SPCC rules. States and Federal agencies may also provide incentives to stripper well operators to maximize the number of these marginally profitable wells that remain operational. Reductions of severance taxes are available in some states, and BLM offers royalty rate reductions for qualifying stripper wells (Williams and Meyers, 1997; 43 CFR Part 3103.4-2).

Clean Water Act

Stripper wells are defined as onshore wells that produce less than 10 barrels of oil per day, are operating at the maximum feasible rate of production, and operate in accordance with recognized conservation practices (40 CFR Part 435.60) They are currently exempt from onshore point source discharge restrictions discussed above in Section VI.B.1. As a result, technology-based limitations instead are developed on a case-by-case basis or in a state-wide general permit.

VI.B.4. State Statutes

In addition to the federal laws described above, most oil-producing states develop other laws affecting oil and gas extraction and production. These include permitting, bonding, temporary abandonment, and plans for plugging orphan wells. Each oil-producing state has a regulatory body, and most require operators to obtain a well permit before drilling. Historically, permitting has been required in these places in order to ensure an efficient and safe mechanism for withdrawing oil from reservoirs by preventing wells from being drilled too close together (Williams and Meyers, 1997).

Nearly all oil-producing states require some form of security or financial assurance for those operators seeking a permit, in order to ensure proper plugging and abandonment. The form of assurance varies from state to state, but the most commonly accepted are surety bonds, certificates of deposit, and cash. The amount of money required for security can vary as well; the amounts range from $10,000 in Kentucky and Tennessee to a minimum of $200,000 in Alaska (IOGCC, 1996).

Laws for temporary abandonment of wells differ among states. (See Section III.B. for a discussion of temporary abandonment.) In general, States are reluctant to require plugging of wells that have significant potential for oil production (and state revenues), yet they seek to avoid problems associated with inactive and unattended wells. As a result, most states require inactive wells to gain state approval for temporary abandonment. (The term temporary abandonment is used for wells that are inactive with state approval.) Most states allow some period of time of inactivity (usually six months to one year) without approval. At this point, however, states may require a statement of future use from the operator; this statement might include extensive geological and engineering information and a schedule for returning the well to production. As part of a temporary abandonment permit, a state may require periodical mechanical integrity tests (MITs) to ensure that the temporarily abandoned well does not pose a threat to the environment (IOGCC, 1996).

Finally, many states have established plugging funds to ensure that wells that pose a threat to the environment but are without financial assurance are properly plugged. These wells, often called orphan wells (see Section III.C.), are identified and prioritized by any number of methods, and are plugged as funds become available and procurement issues are settled. Funding sources vary among states; in some states, such as Arkansas, California, and Mississippi, funding comes directly from the government's general fund or from the regulatory body's budget, while in others the programs are funded through permit fees, portions of oil taxes, bond forfeitures, or penalties (IOGCC, 1996).

In 1990, the Interstate Oil and Gas Compact Commission (IOGCC) developed guidelines for state oil and gas exploration and production waste management program. In 1991, IOGCC began reviewing state programs against the guidelines. State reviews were conducted by stakeholder teams. Review teams wrote reports of their findings, including strengths and weaknesses, and made recommendations for program improvements. Seventeen state programs were reviewed between 1991 and 1997. These reports are an excellent source of state-specific regulations and programs. State reviews can be obtained from IOGCC by calling (405) 525-3556 and from the IOGCC Website at *www.iogcc.oklaosf.state.ok.us/.* The state review program has subsequently been managed by STRONGER, Inc., a non-profit corporation.

For more information on IOGCC and STRONGER, Inc., see Section VIII.A.2., State Activities.

VI.C. Pending and Proposed Regulatory Requirements

Clean Water Act (CWA)

Proposed Phase II NPDES Storm Water Regulations
Under this proposal, construction sites between one and five acres would be regulated under the NPDES storm water program. The oil and gas exploration and production industry might be impacted by this rule during onshore drilling site preparations. Possible requirements include: the submission of a Notice of Intent (NOI) that would include general information and a certification that the activity will not impact endangered or threatened species, development and implementation of a Storm Water Pollution Prevention Plan (SWPPP) and use of best management practices (BMP) to minimize the discharge of pollutants from the site, and submission of a Notice of Termination (NOT) when final stabilization of the site has been achieved as defined in the permit. Finalization of the rule is anticipated in November 1999 (George Utting, EPA, Office of Water, (202) 260-9530 or John Kosco, EPA, Office of Water, (202) 260-6385).

Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids
This proposed rule would amend the technology-based effluent limitations guidelines and standards for the discharge of pollutants from oil and gas drilling operations associated with the use of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids into the waters of the United States. This proposed rule would apply to existing and new facilities in the offshore subcategory and the Cook Inlet portion of the coastal subcategory of the oil and gas extraction point source category. The final rule is scheduled for December 2000. (Carey A. Johnston, EPA, Office of Water, (202) 260-7186).

Revisions to the Oil Pollution Prevention Regulation
Three separate proposals, in 1991, 1993, and 1997, had been offered to amend the text of 40 CFR Part 112, which includes requirements for sites to develop spill prevention control and countermeasures (SPCC) plans. The current proposed rule is a consolidation of the three proposals. The goals of the new rule are to give more flexibility with paperwork and to reduce the burden of information collection for some facilities. Two considerations will be emphasized during the rule development: the importance of good engineering practices and the value of site-specific flexibility. A final rule is

expected during Spring, 2000. (Hugo Fleischman, EPA, Office of Solid Waste and Emergency Response, (703) 603-8769).

Emergency Planning and Community Right-To-Know Act (EPCRA)

Addition of Oil and Gas Exploration and Production to the Toxic Release Inventory

A long-term consideration is the addition of the oil and gas extraction industry to regulation under EPCRA section 313, which requires reporting to the Toxics Release Inventory (TRI). The possible addition of the industry was considered carefully in 1996, but was not added at that time. The proposal may enter the proposed rule stage in December, 2000, but no definite schedule had been set at the time of the publication of this document. (Tim Crawford, EPA, Office of Prevention, Pesticides, and Toxic Substances, (202) 260-1715).

VII. COMPLIANCE AND ENFORCEMENT HISTORY

Background

Until recently, EPA has focused much of its attention on measuring compliance with specific environmental statutes. This approach allows the Agency to track compliance with the Clean Air Act, the Resource Conservation and Recovery Act, the Clean Water Act, and other environmental statutes. Within the last several years, the Agency has begun to supplement single-media compliance indicators with facility-specific, multimedia indicators of compliance. In doing so, EPA is in a better position to track compliance with all statutes at the facility level, and within specific industrial sectors.

A major step in building the capacity to compile multimedia data for industrial sectors was the creation of EPA's Integrated Data for Enforcement Analysis (IDEA) system. IDEA has the capacity to "read into" the Agency's single-media databases, extract compliance records, and match the records to individual facilities. The IDEA system can match Air, Water, Waste, Toxics/Pesticides/EPCRA, TRI, and Enforcement Docket records for a given facility, and generate a list of historical permit, inspection, and enforcement activity. IDEA also has the capability to analyze data by geographic area and corporate holder. As the capacity to generate multimedia compliance data improves, EPA will make available more in-depth compliance and enforcement information. Additionally, sector-specific measures of success for compliance assistance efforts are under development.

Compliance and Enforcement Profile Description

Using inspection, violation and enforcement data from the IDEA system, this section provides information regarding the historical compliance and enforcement activity of this sector. In order to mirror the facility universe reported in the Toxic Chemical Profile, the data reported within this section consists of records only from the TRI reporting universe. With this decision, the selection criteria are consistent across sectors with certain exceptions. For the sectors that do not normally report to the TRI program, data have been provided from EPA's Facility Indexing System (FINDS) which tracks facilities in all media databases. Please note, in this section, EPA does not attempt to define the actual number of facilities that fall within each sector. Instead, the section portrays the records of a subset of facilities within the sector that are well defined within EPA databases.

As a check on the relative size of the full sector universe, most notebooks contain an estimated number of facilities within the sector according to the Bureau of Census (See Section II). With sectors dominated by small businesses, such as metal finishers and printers, the reporting universe within the EPA databases may be small in comparison to Census data. However, the group selected for inclusion in this data analysis section should be consistent with this sector's general make-up.

Following this introduction is a list defining each data column presented within this section. These values represent a retrospective summary of inspections and enforcement actions, and reflect solely EPA, State, and local compliance assurance activities that have been entered into EPA databases. To identify any changes in trends, the EPA ran two data queries, one for the past five calendar years (April 1, 1992 to March 31, 1997) and the other for the most recent twelve-month period (April 1, 1996 to March 31, 1997). The five-year analysis gives an average level of activity for that period for comparison to the more recent activity.

Because most inspections focus on single-media requirements, the data queries presented in this section are taken from single media databases. These databases do not provide data on whether inspections are state/local or EPA-led. However, the table breaking down the universe of violations does give the reader a crude measurement of the EPA's and states' efforts within each media program. The presented data illustrate the variations across EPA Regions for certain sectors.[3] This variation may be attributable to state/local data entry variations, specific geographic concentrations, proximity to population centers, sensitive ecosystems, highly toxic chemicals used in production, or historical noncompliance. Hence, the exhibited data do not rank regional performance or necessarily reflect which regions may have the most compliance problems.

Compliance and Enforcement Data Definitions

General Definitions

Facility Indexing System (FINDS) -- assigns a common facility number to EPA single-media permit records. The FINDS identification number allows EPA to compile and review all permit, compliance, enforcement and pollutant release data for any given regulated facility.

Integrated Data for Enforcement Analysis (IDEA) -- is a data integration system that can retrieve information from the major EPA program office databases. IDEA uses the FINDS identification number to link separate data

[3] EPA Regions include the following states: I (CT, MA, ME, RI, NH, VT); II (NJ, NY, PR, VI); III (DC, DE, MD, PA, VA, WV); IV (AL, FL, GA, KY, MS, NC, SC, TN); V (IL, IN, MI, MN, OH, WI); VI (AR, LA, NM, OK, TX); VII (IA, KS, MO, NE); VIII (CO, MT, ND, SD, UT, WY); IX (AZ, CA, HI, NV, Pacific Trust Territories); X (AK, ID, OR, WA).

records from EPA's databases. This allows retrieval of records from across media or statutes for any given facility, thus creating a ?master list" of records for that facility. Some of the data systems accessible through IDEA are: AFS (Air Facility Indexing and Retrieval System, Office of Air and Radiation), PCS (Permit Compliance System, Office of Water), RCRIS (Resource Conservation and Recovery Information System, Office of Solid Waste), NCDB (National Compliance Data Base, Office of Prevention, Pesticides, and Toxic Substances), CERCLIS (Comprehensive Environmental Response, Compensation, and Liability Information System, Office of Solid Waste and Emergency Response), and TRIS (Toxics Release Inventory System). IDEA also contains information from outside sources such as Dun and Bradstreet and the Occupational Safety and Health Administration (OSHA). Most data queries displayed in notebook sections IV and VII were conducted using IDEA.

Data Table Column Heading Definitions

Facilities in Search -- are based on the universe of Toxic Release Inventory (TRI) reporters within the listed SIC code range. For industries not covered under TRI reporting requirements (oil and gas extraction, metal mining, nonmetallic mineral mining, electric power generation, ground transportation, water transportation, and dry cleaning), or industries in which only a very small fraction of facilities report to TRI (e.g., printing), the notebook uses the FINDS universe for executing data queries. The SIC code range selected for each search is defined by each notebook's selected SIC code coverage described in Section II.

Facilities Inspected -- indicates the level of EPA and state agency inspections for the facilities in this data search. These values show what percentage of the facility universe is inspected in a one-year or five-year period.

Number of Inspections -- measures the total number of inspections conducted in this sector. An inspection event is counted each time it is entered into a single media database.

Average Time Between Inspections -- provides an average length of time, expressed in months, between compliance inspections at a facility within the defined universe.

Facilities with One or More Enforcement Actions -- expresses the number of facilities that were the subject of at least one enforcement action within the defined time period. This category is broken down further into federal and state actions. Data are obtained for administrative, civil/judicial, and criminal enforcement actions. A facility with multiple enforcement actions is only counted once in this column, e.g., a facility with 3 enforcement actions counts as 1 facility.

Total Enforcement Actions -- describes the total number of enforcement actions identified for an industrial sector across all environmental statutes. A facility with multiple enforcement actions is counted multiple times, e.g., a facility with 3 enforcement actions counts as 3.

State Lead Actions -- shows what percentage of the total enforcement actions are taken by state and local environmental agencies. Varying levels of use by states of EPA data systems may limit the volume of actions recorded as state enforcement activity. Some states extensively report enforcement activities into EPA data systems, while other states may use their own data systems.

Federal Lead Actions -- shows what percentage of the total enforcement actions are taken by the United States Environmental Protection Agency. This value includes referrals from state agencies. Many of these actions result from coordinated or joint state/federal efforts.

Enforcement to Inspection Rate -- is a ratio of enforcement actions to inspections, and is presented for comparative purposes only. This ratio is a rough indicator of the relationship between inspections and enforcement. It relates the number of enforcement actions and the number of inspections that occurred within the one-year or five-year period. This ratio includes the inspections and enforcement actions reported under the Clean Water Act (CWA), the Clean Air Act (CAA) and the Resource Conservation and Recovery Act (RCRA). Inspections and actions from the TSCA/FIFRA/EPCRA database are not factored into this ratio because most of the actions taken under these programs are not the result of facility inspections. Also, this ratio does not account for enforcement actions arising from non-inspection compliance monitoring activities (e.g., self-reported water discharges) that can result in enforcement action within the CAA, CWA, and RCRA.

Facilities with One or More Violations Identified -- indicates the percentage of inspected facilities having a violation identified in one of the following data categories: In Violation or Significant Violation Status (CAA); Reportable Noncompliance, Current Year Noncompliance, Significant Noncompliance (CWA); Noncompliance and Significant Noncompliance (FIFRA, TSCA, and EPCRA); Unresolved Violation and Unresolved High Priority Violation (RCRA). The values presented for this column reflect the extent of noncompliance within the measured time frame, but do not distinguish between the severity of the noncompliance. Violation status may be a precursor to an enforcement action, but does not necessarily indicate that an enforcement action will occur.

Media Breakdown of Enforcement Actions and Inspections -- four columns identify the proportion of total inspections and enforcement actions within EPA Air, Water, Waste, and TSCA/FIFRA/EPCRA databases. Each column is a percentage of either the ?Total Inspections," or the ?Total Actions" column.

VII.A. Oil and Gas Extraction Industry Compliance History

Table 14 provides an overview of the reported compliance and enforcement data for the oil and gas extraction industry over the past five years (April 1992 to April 1997). These data are also broken out by EPA Regions thereby permitting geographical comparisons. A few points evident from the data are listed below.

- Over half of the inspections (3,094) and a majority of the enforcement actions (175) during the five year period were conducted in Region VI, which comprises Texas, Oklahoma, Louisiana, New Mexico, and Arkansas. More than half of the oil and gas production activity for the nation is centered in these states.

- Region II has among the fewest facilities, but held the most inspections per facility (an average of an inspection per 12 months at each facility) and had the highest enforcement to inspection ratio (0.17).

- Region VIII had the least frequent inspections (an average of 69 months between inspections) and one of the lowest enforcement to inspection ratios (0.04).

- Nearly 80 percent of the enforcement actions were state-led. The only Region where the majority of actions were federally-led was Region X, in which many oil fields are on Federal land in Alaska.

Table 14: Five-Year Enforcement and Compliance Summary for the Oil and Gas Industry

A	B	C	D	E	F	G	H	I	J
Region	**Facilities in Search**	**Facilities Inspecte d**	**Number of Inspections**	**Average Months Between Inspections**	**Facilities with 1 or More Enforcement Actions**	**Total Enforcemen t Actions**	**Percent State Lead Actions**	**Percent Federal Lead Actions**	**Enforcement to Inspection Rate**
I	3	2	5	36	0	0	0%	0%	--
II	20	12	100	12	2	17	94%	6%	0.17
III	100	26	159	38	6	7	100%	0%	0.04
IV	179	107	590	18	0	0	0%	0%	--
V	66	35	166	24	2	2	50%	50%	0.01
VI	2,666	1,097	3,094	52	93	175	75%	25%	0.06
VII	50	27	114	26	0	0	0%	0%	--
VIII	1,291	432	1,120	69	18	49	84%	16%	0.04
IX	208	124	584	21	20	48	96%	4%	0.08
X	93	40	139	40	8	11	18%	82%	0.08
TOTAL	4,676	1,902	6,071	46	149	309	79%	21%	0.05

VII.B. Comparison of Enforcement Activity Between Selected Industries

Tables 15 and 16 allow the compliance history of the oil and gas sector to be compared to the other industries covered by the industry sector notebooks. Comparisons between Tables 15 and 16 permit the identification of trends in compliance and enforcement records of the various industries by comparing data covering the last five years (April 1992 to April 1997) to that of the past year (April 1996 to April 1997). Some points evident from the data are listed below.

- Oil and gas extraction facilities are inspected much less frequently (46 months between inspections on average) than facilities in most other industries included in the following tables, and the enforcement to inspection ratio (0.05) is among the lowest of the included industries.

- Oil and gas extraction facilities have the lowest percentage of facilities with one or more violations (15 percent) and have one of the lowest percentages of facilities with enforcement actions (three percent).

- The one-year enforcement to inspection ratio (0.03) is significantly less than the five-year ratio (0.05), indicating that enforcement actions may be becoming less frequent per given number of inspections.

Tables 17 and 18 provide a more in-depth comparison between the oil and gas extraction industry and other sectors by breaking out the compliance and enforcement data by environmental statute. As in the previous Tables (Tables 15 and 16), the data cover the last five years (Table 17) and last one year (Table 18) to facilitate the identification of recent trends. A few points evident from the data are listed below.

- The vast majority of both inspections and actions were performed under the Clean Air Act, much more so than in other industries.

- RCRA accounted for a relatively low percentage of the industry's inspections and enforcement actions compared to other industries.

- The inspections performed under RCRA yielded proportionately more actions than those performed under either CAA or CWA.

Table 15: Five-Year Enforcement and Compliance Summary for Selected Industries

A	B	C	D	E	F	G	H	I	J
Industry Sector	**Facilities in Search**	**Facilities Inspected**	**Number of Inspections**	**Average Months Between Inspections**	**Facilities with 1 or More Enforcement Actions**	**Total Enforcement Actions**	**Percent State Lead Actions**	**Percent Federal Lead Actions**	**Enforcement to Inspection Rate**
Metal Mining	1,232	378	1,600	46	63	111	53%	47%	0.07
Coal Mining	3,256	741	3,748	52	88	132	89%	11%	0.04
Oil and Gas Extraction	**4,676**	**1,902**	**6,071**	**46**	**149**	**309**	**79%**	**21%**	**0.05**
Non-Metallic Mineral Mining	5,256	2,803	12,826	25	385	622	77%	23%	0.05
Textiles	355	267	1,465	15	53	83	90%	10%	0.06
Lumber and Wood	712	473	2,767	15	134	265	70%	30%	0.10
Furniture	499	386	2,379	13	65	91	81%	19%	0.04
Pulp and Paper	484	430	4,630	6	150	478	80%	20%	0.10
Printing	5,862	2,092	7,691	46	238	428	88%	12%	0.06
Inorganic Chemicals	441	286	3,087	9	89	235	74%	26%	0.08
Resins and Manmade Fibers	329	263	2,430	8	93	219	76%	24%	0.09
Pharmaceuticals	164	129	1,201	8	35	122	80%	20%	0.10
Organic Chemicals	425	355	4,294	6	153	468	65%	35%	0.11
Agricultural Chemicals	263	164	1,293	12	47	102	74%	26%	0.08
Petroleum Refining	156	148	3,081	3	124	763	68%	32%	0.25
Rubber and Plastic	1,818	981	4,383	25	178	276	82%	18%	0.06
Stone, Clay, Glass and Concrete	615	388	3,474	11	97	277	75%	25%	0.08
Iron and Steel	349	275	4,476	5	121	305	71%	29%	0.07
Metal Castings	669	424	2,535	16	113	191	71%	29%	0.08
Nonferrous Metals	203	161	1,640	7	68	174	78%	22%	0.11
Fabricated Metal Products	2,906	1,858	7,914	22	365	600	75%	25%	0.08
Electronics	1,250	863	4,500	17	150	251	80%	20%	0.06
Automobile Assembly	1,260	927	5,912	13	253	413	82%	18%	0.07
Aerospace	**237**	184	1,206	12	67	127	75%	25%	0.10
Shipbuilding and Repair	44	37	243	9	20	32	84%	16%	0.13
Ground Transportation	7,786	3,263	12,904	36	375	774	84%	16%	0.06
Water Transportation	514	192	816	38	36	70	61%	39%	0.09
Air Transportation	444	231	973	27	48	97	88%	12%	0.10
Fossil Fuel Electric Power	3,270	2,166	14,210	14	403	789	76%	24%	0.06
Dry Cleaning	6,063	2,360	3,813	95	55	66	95%	5%	0.02

Table 16: One-Year Enforcement and Compliance Summary for Selected Industries

A	B	C	D	E		F		G	H
				Facilities with 1 or More Violations		Facilities with 1 or more Enforcement Actions			
Industry Sector	Facilities in Search	Facilities Inspected	Number of Inspections	Number	Percent*	Number	Percent*	Total Enforcement Actions	Enforcement to Inspection Rate
Metal Mining	1,232	142	211	102	72%	9	6%	10	0.05
Coal Mining	3,256	362	765	90	25%	20	6%	22	0.03
Oil and Gas Extraction	**4,676**	**874**	**1,173**	**127**	**15%**	**26**	**3%**	**34**	**0.03**
Non-Metallic Mineral Mining	5,256	1,481	2,451	384	26%	73	5%	91	0.04
Textiles	355	172	295	96	56%	10	6%	12	0.04
Lumber and Wood	712	279	507	192	69%	44	16%	52	0.10
Furniture	499	254	459	136	54%	9	4%	11	0.02
Pulp and Paper	484	317	788	248	78%	43	14%	74	0.09
Printing	5,862	892	1,363	577	65%	28	3%	53	0.04
Inorganic Chemicals	441	200	548	155	78%	19	10%	31	0.06
Resins and Manmade Fibers	329	173	419	152	88%	26	15%	36	0.09
Pharmaceuticals	164	80	209	84	105%	8	10%	14	0.07
Organic Chemicals	425	259	837	243	94%	42	16%	56	0.07
Agricultural Chemicals	263	105	206	102	97%	5	5%	11	0.05
Petroleum Refining	156	132	565	129	98%	58	44%	132	0.23
Rubber and Plastic	1,818	466	791	389	83%	33	7%	41	0.05
Stone, Clay, Glass and Concrete	615	255	678	151	59%	19	7%	27	0.04
Iron and Steel	349	197	866	174	88%	22	11%	34	0.04
Metal Castings	669	234	433	240	103%	24	10%	26	0.06
Nonferrous Metals	203	108	310	98	91%	17	16%	28	0.09
Fabricated Metal	2,906	849	1,377	796	94%	63	7%	83	0.06
Electronics	1,250	420	780	402	96%	27	6%	43	0.06
Automobile Assembly	1,260	507	1,058	431	85%	35	7%	47	0.04
Aerospace	237	119	216	105	88%	8	7%	11	0.05
Shipbuilding and Repair	44	22	51	19	86%	3	14%	4	0.08
Ground Transportation	7,786	1,585	2,499	681	43%	85	5%	103	0.04
Water Transportation	514	84	141	53	63%	10	12%	11	0.08
Air Transportation	444	96	151	69	72%	8	8%	12	0.08
Fossil Fuel Electric Power	3,270	1,318	2,430	804	61%	100	8%	135	0.06
Dry Cleaning	6,063	1,234	1,436	314	25%	12	1%	16	0.01

*Percentages in Columns E and F are based on the number of facilities inspected (Column C). Percentages can exceed 100% because violations and actions can occur without a facility inspection.

Table 17: Five-Year Inspection and Enforcement Summary by Statute for Selected Industries

				Clean Air Act		Clean Water Act		RCRA		FIFRA/TSCA/ EPCRA/Other	
Industry Sector	**Facilities Inspected**	**Total Inspections**	**Total Enforcement Actions**	**% of Total Inspections**	**% of Total Actions**	**% of Total Inspections**	**% of Total Actions**	**% of Total Inspections**	**% of Total Actions**	**% of Total Inspections**	**% of Total Actions**
Metal Mining	378	1,600	111	39%	19%	52%	52%	8%	12%	1%	17%
Coal Mining	741	3,748	132	57%	64%	38%	28%	4%	8%	1%	1%
Oil and Gas Extraction	**1,902**	**6,071**	**309**	**75%**	**65%**	**16%**	**14%**	**8%**	**18%**	**0%**	**3%**
Non-Metallic Mineral Mining	2,803	12,826	622	83%	81%	14%	13%	3%	4%	0%	3%
Textiles	267	1,465	83	58%	54%	22%	25%	18%	14%	2%	6%
Lumber and Wood	473	2,767	265	49%	47%	6%	6%	44%	31%	1%	16%
Furniture	386	2,379	91	62%	42%	3%	0%	34%	43%	1%	14%
Pulp and Paper	430	4,630	478	51%	59%	32%	28%	15%	10%	2%	4%
Printing	2,092	7,691	428	60%	64%	5%	3%	35%	29%	1%	4%
Inorganic Chemicals	286	3,087	235	38%	44%	27%	21%	34%	30%	1%	5%
Resins and Manmade Fibers	263	2,430	219	35%	43%	23%	28%	38%	23%	4%	6%
Pharmaceuticals	129	1,201	122	35%	49%	15%	25%	45%	20%	5%	5%
Organic Chemicals	355	4,294	468	37%	42%	16%	25%	44%	28%	4%	6%
Agricultural Chemicals	164	1,293	102	43%	39%	24%	20%	28%	30%	5%	11%
Petroleum Refining	148	3,081	763	42%	59%	20%	13%	36%	21%	2%	7%
Rubber and Plastic	981	4,383	276	51%	44%	12%	11%	35%	34%	2%	11%
Stone, Clay, Glass and Concrete	388	3,474	277	56%	57%	13%	9%	31%	30%	1%	4%
Iron and Steel	275	4,476	305	45%	35%	26%	26%	28%	31%	1%	8%
Metal Castings	424	2,535	191	55%	44%	11%	10%	32%	31%	2%	14%
Nonferrous Metals	161	1,640	174	48%	43%	18%	17%	33%	31%	1%	10%
Fabricated Metal	1,858	7,914	600	40%	33%	12%	11%	45%	43%	2%	13%
Electronics	863	4,500	251	38%	32%	13%	11%	47%	50%	2%	7%
Automobile Assembly	927	5,912	413	47%	39%	8%	9%	43%	43%	2%	9%
Aerospace	184	1,206	127	34%	38%	10%	11%	54%	42%	2%	9%
Shipbuilding and Repair	37	243	32	39%	25%	14%	25%	42%	47%	5%	3%
Ground Transportation	3,263	12,904	774	59%	41%	12%	11%	29%	45%	1%	3%
Water Transportation	192	816	70	39%	29%	23%	34%	37%	33%	1%	4%
Air Transportation	231	973	97	25%	32%	27%	20%	48%	48%	0%	0%
Fossil Fuel Electric Power	2,166	14,210	789	57%	59%	32%	26%	11%	10%	1%	5%
Dry Cleaning	2,360	3,813	66	56%	23%	3%	6%	41%	71%	0%	0%

Table 18: One-Year Inspection and Enforcement Summary by Statute for Selected Industries

Industry Sector	Facilities Inspected	Total Inspections	Total Enforcement Actions	Clean Air Act		Clean Water Act		RCRA		FIFRA/TSCA/ EPCRA/Other	
				% of Total Inspections	% of Total Actions	% of Total Inspections	% of Total Actions	% of Total Inspections	% of Total Actions	% of Total Inspections	% of Total Actions
Metal Mining	142	211	10	52%	0%	40%	40%	8%	30%	0%	30%
Coal Mining	362	765	22	56%	82%	40%	14%	4%	5%	0%	0%
Oil and Gas Extraction	**874**	**1,173**	**34**	**82%**	**68%**	**10%**	**9%**	**9%**	**24%**	**0%**	**0%**
Non-Metallic Mineral Mining	1,481	2,451	91	87%	89%	10%	9%	3%	2%	0%	0%
Textiles	172	295	12	66%	75%	17%	17%	17%	8%	0%	0%
Lumber and Wood	279	507	52	51%	30%	6%	5%	44%	25%	0%	40%
Furniture	254	459	11	66%	45%	2%	0%	32%	45%	0%	9%
Pulp and Paper	317	788	74	54%	73%	32%	19%	14%	7%	0%	1%
Printing	892	1,363	53	63%	77%	4%	0%	33%	23%	0%	0%
Inorganic Chemicals	200	548	31	35%	59%	26%	9%	39%	25%	0%	6%
Resins and Manmade Fibers	173	419	36	38%	51%	24%	38%	38%	5%	0%	5%
Pharmaceuticals	80	209	14	43%	71%	11%	14%	45%	14%	0%	0%
Organic Chemicals	259	837	56	40%	54%	13%	13%	47%	34%	0%	0%
Agricultural Chemicals	105	206	11	48%	55%	22%	0%	30%	36%	0%	9%
Petroleum Refining	132	565	132	49%	67%	17%	8%	34%	15%	0%	10%
Rubber and Plastic	466	791	41	55%	64%	10%	13%	35%	23%	0%	0%
Stone, Clay, Glass and Concrete	255	678	27	62%	63%	10%	7%	28%	30%	0%	0%
Iron and Steel	197	866	34	52%	47%	23%	29%	26%	24%	0%	0%
Metal Castings	234	433	26	60%	58%	10%	8%	30%	35%	0%	0%
Nonferrous Metals	108	310	28	44%	43%	15%	20%	41%	30%	0%	7%
Fabricated Metal	849	1,377	83	46%	41%	11%	2%	43%	57%	0%	0%
Electronics	420	780	43	44%	37%	14%	5%	43%	53%	0%	5%
Automobile Assembly	507	1,058	47	53%	47%	7%	6%	41%	47%	0%	0%
Aerospace	119	216	11	37%	36%	7%	0%	54%	55%	1%	9%
Shipbuilding and Repair	22	51	4	54%	0%	11%	50%	35%	50%	0%	0%
Ground Transportation	1,585	2,499	103	64%	46%	11%	10%	26%	44%	0%	1%
Water Transportation	84	141	11	38%	9%	24%	36%	38%	45%	0%	9%
Air Transportation	96	151	12	28%	33%	15%	42%	57%	25%	0%	0%
Fossil Fuel Electric Power	1,318	2,430	135	59%	73%	32%	21%	9%	5%	0%	0%
Dry Cleaning	1,234	1,436	16	69%	56%	1%	6%	30%	38%	0%	0%

VII.C. Review of Major Legal Actions

Major Cases/Supplemental Environmental Projects

This section provides summary information about major cases that have affected this sector, and a list of Supplemental Environmental Projects (SEPs).

VII.C.1. Review of Major Cases

As indicated in EPA's *Enforcement Accomplishments Report* publications for FY 1996, FY 1997, and FY 1998 and a U.S. Department of Justice press release, seven significant enforcement actions have been resolved recently for the oil and gas extraction industry.

Three cases involved violations of the Clean Water Act. Two cases involved violations of National Pollution Discharge Elimination System (NPDES) discharge limits. The Cook Inlet Oil and Gas Platforms (owned by Marathon, Shell, and Unocal) agreed to pay $212,000 for allegedly violating NPDES permits for 18 offshore platforms in Cook Inlet, Alaska. In a separate settlement, BP Exploration, Inc. agreed to pay $59,900 in response to an administrative complaint that the levels of fecal coliform bacteria, BOD, TRC, pH and flow were beyond its NPDES permit levels between January 1992 and October 1995.

The CWA violation settled in U.S. v. Berry Petroleum was part of a multi-agency (federal and state) case relating to a crude oil spill of 2,000 barrels from an oil production facility in a wetland area located adjacent to a California state beach. The spill contaminated the wetlands, adjacent ocean, and nearby beaches. It was determined that the spill occurred, in large part, because the facility failed to implement its EPA-mandated SPCC plan. Berry Petroleum paid $800,000 to EPA for the CWA violation in addition to $1.06 million in penalties to the California Regional Water Quality Control Board, the U.S. Fish and Wildlife Service, and other federal and state agencies. Berry also transferred $1,315,000 to a trust fund administered by the National Fish and Wildlife Foundation that will be used for long term restoration of the site.

A settlement in U.S. (Sac and Fox Nation) v. Tenneco Oil Company was reached over an alleged SDWA violation. Surface and groundwater on land of the Sac and Fox Nation was contaminated near areas of oil leases maintained by Tenneco between 1924 and 1989. Tenneco is required to provide the Sac and Fox Nation with a potable water supply of 207 sustainable gallons per minute and $1.16 million in cash. The overall dollar value of the settlement is over $3.5 million.

An alleged CAA violation was settled with Vastar Resources, Inc. and ARCO, regarding their facility on the Southern Ute Indian Reservation in La Plata County, CO. Vastar (the current owner) and ARCO (the previous owner) failed to install pollution control equipment on gas production engines at the facility. The results were large emissions of carbon monoxide (CO) and savings of $657,412 on the part of Vastar by operating the equipment without the required air emission controls. Vastar complied with EPA self-policing policies, and as a result the company only paid $137,949 plus $247,000 for the pollution control equipment. Although ARCO came forward at the same time as Vastar, it did not report the emissions while it owned the facility, and as a result did not meet EPA's self-disclosure standards. ARCO did not admit to the allegations, but settled for $519,463, which includes money saved from not using the equipment plus a penalty.

In September 1999, the Department of Justice announced that BP Exploration (Alaska) Inc. pleaded guilty to one felony count related to the illegal disposal of hazardous waste on Alaska's North Slope in violation of CERCLA. BP Exploration had contracted with Doyan Drilling Inc. to drill production wells on Endicott Island. Between 1993 and 1995 Doylan employees illegally injected wastes down the outer rim, or annuli, of the oil wells. BP Exploration failed to report the illegal injections as soon as it learned of the conduct. The wastes included paint thinner and toxic solvents containing lead and chemicals such as benzene, toluene, and methyl chloride. BP Exploration was fined $500,000 and agreed to spend a total of $22 million to resolve the criminal case and related civil claims. The civil settlement requires BP Exploration to pay $6.5 million in penalties to resolve allegations that BP illegally disposed of the hazardous waste and violated the Safe Drinking Water Act. Also under the terms of the agreement, BP Exploration will establish an environmental management system at all of BP Amoco's facilities in the U.S. and Gulf of Mexico that are engaged in the exploration, drilling, or production of oil (U.S. Department of Justice, September 23, 1999).

VII.C.2. Supplementary Environmental Projects (SEPs)

SEPs are compliance agreements that reduce a facility's non-compliance penalty in return for an environmental project that exceeds the value of the reduction. Often, these projects fund pollution prevention activities that can reduce the future pollutant loadings of a facility. Information on SEP cases can be accessed via the internet at the SEP National Database, *es.epa.gov/oeca/sep/*. This information is not comprehensive and provides only a sample of the types of SEPs developed for the oil and gas extraction industry.

One agreement was listed for SIC code 13. George Perry Exploration and Production, in Oceana County, MI, performed a SEP in response to violations of sections 1421 and 1422 of SDWA, in which the company violated the state underground injection control (UIC) program regulations and failed to submit an application for implementation of a UIC program. As a pollution reduction SEP, the company plugged three abandoned production wells to prevent the possible contamination of underground sources of drinking water. The cost of the project was valued at $6,000.

VIII. COMPLIANCE ASSURANCE ACTIVITIES AND INITIATIVES

This section highlights the activities undertaken by this industry sector and public agencies to voluntarily improve the sector's environmental performance. These activities include those initiated independently by industrial trade associations. In this section, the notebook also contains a listing and description of national and regional trade associations.

VIII.A. Sector-related Environmental Programs and Activities

VIII.A.1. Federal Activities

EPA Regional Compliance and Enforcement Activities

Several significant regional activities relating to the oil and gas extraction industry were reported in the 1997 Enforcement and Compliance Assurance Reports. Region VI provided assistance to offshore oil and gas exploration and production facilities with regard to NPDES permits. Region VI sent reporting forms to more than 2,000 facilities for compliance monitoring and reporting of the effluent quality of wastewater discharges from offshore platforms to the Gulf of Mexico. General permitting and reporting questions were explained to increase compliance through approximately 300 telephone conversations with facility operators, consultant, and state and federal agencies. Finally, a presentation on NPDES Offshore General Permit compliance and enforcement was given to approximately 100 permittees in Dallas. Partially as a result of these efforts, the compliance reporting rate is approximately 98 percent.

Region VI also created a work group that addressed the compliance and reporting of over 3,000 injection wells operated by 500 to 600 oil producers in the Osage Mineral Reserve. The group created *Osage Operators' Environmental Handbook* and *Osage Operators' Environmental Manual*, in order to assist small oil producers in complying with Bureau of Indian Affairs (BIA) and EPA requirements.

Region VIII, the U.S. Fish and Wildlife Service (USFWS) and associated states implemented a pilot program regarding problem oil pits (POPs). POPs are open-air pits along with tanks and associated spills at drilling and production sites that lack devices (such as proper netting) to prevent birds from landing on (and becoming stuck in) the layer of oil. This program seeks to address impacts to ground water and surface water as well as impacts to wildlife. The program cooperated with federal and state regulators (Bureau of Land Management, state environmental agencies, and state oil and gas commissions) to perform aerial surveys and ground surveys of oil pits in Colorado, Montana, and Wyoming. The states had the lead whenever possible. It was found that a large number of the pits would be considered POPs and were in noncompliance with applicable federal and state statutes or regulations. To address the high rate of noncompliance, the relevant agencies are mobilizing to offer compliance assistance, informal enforcement, or formal enforcement. All EPA Region VIII states have been completed for this POP effort except Utah, which is planned for completion in 1999 and EPA regions 5 and 7 are pursuing POP programs.

U.S. Department of Energy Oil and Gas Environmental Research and Analysis Program

The Office of Fossil Energy of the Department of Energy (DOE) has initiated several programs that address environmental and regulatory issues in the oil and gas industry. The efforts primarily center around streamlining regulatory procedures that affect the industry and performing research on cost-effective environmental compliance technologies.

The regulatory streamlining efforts attempt three major tasks: coordinating the many federal and state agencies involved with oil and gas regulation, including EPA, the Bureau of Land Management (BLM), and relevant state agencies; incorporating more risk-based decision making into regulatory, enforcement, and compliance decisions; and reducing impediments to technology implementation.

In its efforts to coordinate regulatory agencies, DOE worked with a group including the Interstate Oil and Gas Compact Commission (IOGCC), BLM, industry, and environmental groups to standardize permit applications in different states and on federal lands. The group also identified seven areas of regulatory responsibility that could be transferred from federal to state agencies to reduce overlapping activities within states.

DOE is also attempting to broaden the use of risk-based decision making. In one project, DOE is working with California, Kansas, and Oklahoma to expand exemptions for costly Area of Review (AOR) analyses of surrounding areas prior to the permitting of a disposal or injection well. AOR analyses investigate the potential of aquifer contamination by a proposed disposal well; new DOE methodology would limit the necessity of AOR studies in areas predetermined to have little risk.

The DOE environmental program also works to remove impediments to technology implementation. An example is shown in the case of newly developed synthetic drilling fluids, which show promise in increasing drilling efficiency and safety, particularly in deepwater drilling. Existing EPA regulations, however, limit their use. In 1994, DOE worked with industry and EPA to re-evaluate the regulations that affect these synthetic fluids. Consequently, EPA is in the process of revising regulations to clarify the terms under which industry may be allowed to use the technology. The use of these fluids could save the industry over $50 million annually.

Finally, DOE is assisting in the development of pollution prevention and waste management technologies. DOE's Sandia National Laboratories are developing a laser-equipped camera that can detect methane leaks in pipes. Argonne National Laboratory is undertaking a study to determine whether naturally occurring radioactive material (NORM), which may be found in well fluids, can be disposed of on-site in some locations, in order to reduce disposal costs. DOE also performs or funds research on produced water disposal; this includes further investigation into underground injection systems and development of a treatment for produced water into potable water in arid regions such as California. (Contact: *www.fe.doe.gov/ oil_gas/oilgas7.html* or William Hochheiser, Environmental Scientist, at (202) 586-5614 or e-mail william.hochheiser@hq.doe.gov.)

U.S. EPA Voluntary Self-Disclosure Policy

In 1996, EPA adopted its final policy on incentives for self-evaluation and self-disclosure of violations. Through this policy, the Agency aims to protect public health and the environment by reducing civil penalties and not recommending criminal prosecution for regulated entities that voluntarily discover, disclose and correct violations under the environmental laws that EPA administers.

Under the final policy, where violations are found through voluntary environmental audits or efforts that reflect a regulated entity's due diligence (i.e., systematic efforts to prevent, detect and correct violations, as defined in the policy), and all of the policy's conditions are met, EPA will not seek gravity-based penalties and will generally not recommend criminal prosecution against the company if the violation results from the unauthorized criminal conduct of an employee. Where violations are discovered by means other than environmental audits or due diligence efforts, but are promptly disclosed and expeditiously corrected, EPA will reduce gravity-based penalties by 75 percent provided that all of the other conditions of the policy are met. EPA retains its discretion to recover economic benefit gained as a result of noncompliance, so that companies won't be able to obtain an economic advantage over their competitors by delaying their investment in compliance.

In addition to prompt disclosure and correction, the policy requires companies to prevent recurrence of the violation and to remedy any environmental harm. Repeated violations or those which may have presented an imminent and substantial endangerment or resulted in serious harm are excluded from the policy's coverage. Corporations remain criminally liable for violations resulting from conscious disregard of their legal duties, and individuals remain liable for criminal wrongdoing.

Although the final policy restates EPA's practice of not routinely requesting environmental audit reports, it does contain two provisions ensuring public access to information. First, EPA may require as a condition of penalty mitigation that a description of the regulated entity's due diligence efforts be made publicly available. Second, where EPA requires that a regulated entity enter into a written agreement, administrative consent order or judicial consent decree to satisfy the policy's conditions, those agreements will be made publicly available.

VIII.A.2. State Activities

The oil and gas industry is primarily regulated at the state level. Four organizations are discussed in this section that strongly influence state compliance assurance and waste minimization initiatives. Interstate Oil and Gas Compact Commission (IOGCC) coordinates oil and gas issues among oil and gas producing states, including environmental concerns. State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER, Inc.) is a non-profit corporation that develops guidelines for state oil and gas production waste regulatory programs and coordinates state reviews. The Ground Water Protection Council (GWPC) brings together state and federal regulators, industry, and others to address both underground injection control and groundwater protection issues. Finally, the Waste Minimization Program of the Texas Railroad Commission is in many ways a model for other states in disseminating cost-effective waste minimization solutions. While many states have waste minimization programs for underground injection wells, the Texas Railroad Commission has a unique structure among state governments of oil producing states as the regulator of nearly every aspect of the oil and gas extraction industry. The Waste Minimization Program therefore has a wider reach over the industry in the state.

Interstate Oil and Gas Compact Commission (IOGCC)

The IOGCC is an organization of the governors of 30 member states and seven associate states concerned with many aspects of the oil and gas industry. The primary purpose of the compact is to conserve oil and gas by the prevention of physical waste. IOGCC advocates for the rights of the states to govern oil and gas issues within their own borders, and coordinates regulatory efforts among the states to protect oil and gas resources and protect the environment. The organization serves as a forum for government, industry, environmentalists and others to share information and voice opinions on a wide range of topics.

Specifically relating to environmental issues, IOGCC is active in developing state regulatory standards, guidelines, and models for many aspects of the oil and gas industry, including bioremediation, waste disposal, waste minimization, beneficial use of waste, water and air quality, and abandoned sites. One of the most prominent of the IOGCC's efforts with respect to environmental issues has been the development of guidelines and reviews of state extraction and production waste management regulatory programs. Seventeen states representing over 90 percent of the onshore production in the United States have undergone these reviews, and summaries of the reviews are published in individual reports. These reports, in addition to other IOGCC publications, are an excellent source of state-specific regulations and programs. State reviews can be obtained from IOGCC by calling (405) 525-3556, and from the IOGCC Website at: *www.iogcc.oklaosf.state.ok.us/*. Since mid-1999, the state review program has been managed by STRONGER, Inc., a non-profit organization. Also, the IOGCC, through its annual Environmental Stewardship Awards recognizes major and independent operators that are performing environmentally beneficial projects.

State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER, Inc.)

The state review process described above, established by IOGCC, developed guidelines for state oil and gas exploration and production waste regulatory programs and coordinated reviews of state programs until 1997, when the process was terminated. During 1998, several meetings of interested stakeholders were conducted to determine how the process could be revitalized. In early 1999, the IOGCC proposed to EPA that the program be managed by a separate group of stakeholders equally representing the states, industry, and environmental organizations. Such a group was formed, and in June, 1999, was incorporated as a non-profit corporation, State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER, Inc.). STRONGER, Inc. develops updated and revised guidelines for adoption by IOGCC and coordinates state reviews. Guidelines, documents and state review reports are published and distributed by IOGCC. State participation in STRONGER, Inc. is coordinated through the IOGCC State Review Committee.

Ground Water Protection Council (GWPC)

The Ground Water Protection Council (GWPC) is a nonprofit organization whose members consist of state and federal ground water agencies, industry representatives, environmentalists, and concerned citizens. The council seeks to promote and ensure the use of best management practices and fair but effective laws regarding comprehensive ground water protection. The GWPC works with the oil and gas industry via its UIC Class II Division. GWPC can be contacted by calling (405) 516-4972 or visiting their website at *http://gwpc.site.net/*.

Texas Waste Minimization Program

The Waste Minimization Program, run by the Texas Railroad Commission, is a voluntary program intended to provide oil and gas well operators with cost effective waste minimization solutions. The program serves as a technology transfer clearinghouse for information on specific waste streams, such as fugitive VOCs or produced water. The program also performs several forms of outreach:

- A manual outlining general techniques, *Waste Minimization in the Oil Field.*
- One-day workshops.
- A *Waste Minimization Newsletter*, which illustrates case studies of cost-effective programs implemented by operators (the newsletter is published two or three times a year).
- On-site assistance to help operators assess their operations and to develop individualized waste minimization programs.
- WasteMin, an easy-to-use waste minimization planning software package.

The program focuses on discovering and spreading innovative techniques that will add revenue for operators in addition to reducing environmental impacts. (Contact: Jack Ward, (512) 475-4580, or *www.rrc.state.tx.us/divisions/og/key-programs/ogkwast.html*.)

VIII.B. EPA Voluntary Programs

Natural Gas STAR

Natural Gas STAR is a voluntary partnership between EPA and the natural gas industry that was formed to find cost-effective ways of reducing emissions of methane. Methane is a significant concern with regard to the climate change issue; it is second only to carbon dioxide as a component of so-called "greenhouse gases."

Fugitive emissions from the natural gas industry are a substantial source of anthropogenic methane. Natural Gas STAR has two programs: one focusing on production and the other concentrating on distribution and transmission.

The program for producers was launched in 1995, and participants represent approximately 35 percent of the U.S. natural gas production. The primary goals of the producers program are to promote technology transfer and implement best management practices (BMPs) that are cost-effective and that reduce methane emissions. Partners perform the following:

- Submit and execute BMP implementation plans
- Assist in the testing of emerging technologies
- Design new facilities to include BMPs when cost effective.

EPA serves to facilitate the transfer of new technology between members, perform outreach to inform and attract non-members, and address regulatory barriers that may threaten BMP implementation.

By mid-1998, partners had prevented the release of roughly 50 billion cubic feet (Bcf) of methane, worth approximately $100 million. The program has achieved this mark and plans to continue improvements by holding workshops for satellite offices of both member and non-member companies and updating members on new developments through newsletters and reports, among other activities. (Contact: *www.epa.gov/gasstar* or Paul Gunning at (202) 564-9736).

33/50 Program

The 33/50 Program is a groundbreaking program that has focused on reducing pollution from seventeen high-priority chemicals through voluntary partnerships with industry. The program's name stems from its goals: a 33% reduction in toxic releases by 1992, and a 50% reduction by 1995, against a baseline of 1.5 billion pounds of releases and transfers in 1988. The results have been impressive: 1,300 companies joined the 33/50 Program (representing over 6,000 facilities) and reached the national targets a year ahead of schedule. The 33% goal was reached in 1991, and the 50% goal -- a reduction of 745 million pounds of toxic wastes -- was reached in 1994.

Table 19 lists those companies participating in the 33/50 program that reported four-digit SIC codes within 13 to TRI. Some of the companies shown also listed facilities that are not producing oil and gas. The number of facilities within each company that are participating in the 33/50 program and that report oil and gas extraction SIC codes is shown.

Since oil and gas facilities are not currently required to report to TRI under EPCRA section 313 reporting requirements (TRI), only a few oil and gas extraction companies participated in the 33/50 program. Where available and quantifiable against 1988 releases and transfers, each company’s 33/50 goals for 1995 and the actual total releases and transfers and percent reduction between 1988 and 1995 are presented. In each case, the participating oil and gas extraction operations of the partner companies performed significantly better than the company-wide goals, and nearly all facilities attained greater than 50 percent reductions in 33/50 chemicals.

Table 19 shows that six companies comprised of 80 facilities reporting SIC 13 participated in the 33/50 program. For those companies shown with more than one oil and gas facility, all facilities may not have participated in 33/50. The 33/50 goals shown for companies with multiple oil and gas facilities, however, are company-wide, potentially aggregating more than one facility and facilities not carrying out oil and gas extraction operations. In addition to company-wide goals, individual facilities within a company may have had their own 33/50 goals or may be specifically listed as not participating in the 33/50 program. Since the actual percent reductions shown in the last column apply to all of the companies' oil and gas facilities and only oil and gas facilities, direct comparisons to those company goals incorporating non-oil and gas facilities may not be possible. For information on specific facilities participating in 33/50, or to review case studies on corporate accomplishments in reducing waste contact David Sarokin, (202) 260-6907, at the 33/50 Program Office.

With the completion of the 33/50 program, several lessons were learned. Industry and the environment benefitted by this program for several reasons. Companies were willing to participate because cost savings and risk reduction were measurable and no additional record keeping and reporting was required. The goals of the program were clear and simple and EPA allowed industry to achieve the goals in whatever manner they could. Therefore, when companies can see the benefits of environmental programs and be an active part of the decision-making process, they are more likely to participate.

Table 19: Oil and Gas Industry Participation in the 33/50 Program

Parent Company (Headquarters Location)	Company-Owned Oil and Gas Facilities Reporting 33/50 Chemicals	Company-Wide % Reduction Goal[1] (1988-1995)	1988 TRI Releases and Transfers of 33/50 Chemicals (pounds)	1995 TRI Releases and Transfers of 33/50 Chemicals (pounds)	Actual % Reduction for Oil and Gas Facilities (1988-1995)
Amerada Hess Corp. New York, NY	4	50%	2,241,601	567,251	75%
Atlantic Richfield Co. Los Angeles, CA	11	23%	835,443	451,818	46%
Dresser Industries, Inc. Dallas, TX	10	47%	230,202	17,578	92%
Exxon Corp. Irving, TX	17	50%	5,155,264	2,159,535	58%
Texaco, Inc. White Plains, NY	14	49%	713,136	251,152	65%
USX Corp. Pittsburgh, PA	24	25%	9,873,833	1,246,246	87%
TOTAL	80	--	19,049,479	4,693,580	75%

Source: U.S. EPA, OPPTS, 33/50 Program 1998

[1] Company-Wide Reduction Goals aggregate all company-owned facilities which may include facilities not involved with oil and gas production.

Project XL

Project XL was initiated in March 1995 as a part of President Clinton's *Reinventing Environmental Regulation* initiative. The projects seek to achieve cost effective environmental benefits by providing participants regulatory flexibility on the condition that they produce greater environmental benefits. EPA and program participants will negotiate and sign a Final Project Agreement, detailing specific environmental objectives that the regulated entity shall satisfy. EPA will provide regulatory flexibility as an incentive for the participants' superior environmental performance. Participants are encouraged to seek stakeholder support from local governments, businesses, and environmental groups. EPA hopes to implement fifty pilot projects in four categories, including industrial facilities, communities, and government facilities regulated by EPA. Applications will be accepted on a rolling basis. For additional information regarding XL projects, including application procedures and criteria, see the May 23, 1995 Federal Register Notice. (Contact: Fax-on-Demand Hotline (202) 260-8590, Web: www.epa.gov/ProjectXL, or Christopher Knopes in EPA's Office of Reinvention, (202) 260-9298).

Energy Star® Buildings and Green Lights® Partnership

In 1991, EPA introduced Green Lights®, a program designed for businesses and organizations to proactively combat pollution by installing energy-efficient lighting technologies in their commercial and industrial buildings. In April 1995, Green Lights® expanded into Energy Star® Buildings-- a strategy that optimizes whole-building energy-efficiency opportunities.

The energy needed to run commercial and industrial buildings in the United States produces 19 percent of U.S. carbon dioxide emissions, 12 percent of nitrogen oxides, and 25 percent of sulfur dioxide, at a cost of 110 billion dollars a year. If implemented in every U.S. commercial and industrial building, Energy Star® Buildings' upgrade approach could prevent up to 35 percent of the emissions associated with these buildings and cut the nation's energy bill by up to 25 billion dollars annually.

The over 2,500 participants include corporations, small businesses, universities, health care facilities, nonprofit organizations, school districts, and federal and local governments. As of January 1, 1998, Energy Star®Buildings and Green Lights® Program participants have reduced their annual energy use by 7 billion kilowatt hours and annually save more than 517 million dollars. By joining, participants agree to upgrade 90 percent of their owned facilities with energy-efficient lighting and 50 percent of their owned facilities with whole-building upgrades, where profitable, over a seven-year period. Energy Star participants first reduce their energy loads with the Green Lights approach to building tune-ups, then focus on "right sizing" their heating and cooling equipment to match their new energy needs. EPA predicts this strategy will prevent more than 5.5 MMTCE of carbon dioxide by the year 2000. EPA's Office of Air and Radiation is responsible for operating the Energy Star Buildings and Green Lights Program. (Contact the Energy Star Hotline number, (888) STAR-YES ((888) 872-7937) or Maria Tikoff Vargas, Co-Director at (202) 564-9178 or visit the website at www.epa.gov/buildings.)

WasteWi$e Program

The WasteWi$e Program was started in 1994 by EPA's Office of Solid Waste and Emergency Response. The program is aimed at reducing municipal solid wastes by promoting waste prevention, recycling collection and the manufacturing and purchase of recycled products. As of 1998, the program had about 700 business, government, and institutional partners. Partners agree to identify and implement actions to reduce their solid wastes setting waste reduction goals and providing EPA with yearly progress reports for a three year period. EPA, in turn, provides partners with technical assistance, publications, networking opportunities, and national and regional recognition. (Contact: WasteWi$e Hotline at (800) 372-9473).

NICE[3]

The U.S. Department of Energy sponsors a grant program called *National Industrial Competitiveness through Energy, Environment, and Economics* (NICE[3]). The NICE[3] program provides funding to state and industry partnerships (large and small business) for projects demonstrating advances in energy efficiency and clean production technologies. The goal of the NICE[3] program is to demonstrate the performance and economics of innovative technologies in the U.S., leading to the commercialization of improved industrial manufacturing processes. These processes should conserve energy, reduce waste, and improve industrial cost-competitiveness. Industry applicants must submit project proposals through a state energy, pollution prevention, or business development office. The following focus industries, which represent the dominant energy users and waste generators in the U.S. manufacturing sector, are of particular interest to the program: Aluminum, Chemicals, Forest Products, Glass, Metal-casting, and Steel. Awardees receive a one-time, three-year grant of up to $400,000, representing up to 50 percent of a project's total cost. In addition, up to $25,000 is available to support the state applicant's cost share. (Contact: *www.oit.doe.gov/Access/nice3*, Steve Blazek, DOE, (303) 275-4723 or Eric Hass, DOE, (303) 275-4728)

Design for the Environment (DfE) Program

DfE is working with several industries to identify cost-effective pollution prevention strategies that reduce risks to workers and the environment. DfE helps businesses compare and evaluate the performance, cost, pollution prevention benefits, and human health and environmental risks associated with existing and alternative technologies. The goal of these projects is to encourage businesses to consider and use cleaner products, processes, and technologies. For more information about the DfE Program, call (202) 260-1678. To obtain copies of DfE materials or for general information about DfE, contact EPA's Pollution Prevention Information Clearinghouse at (202) 260-1023 or visit the DfE Website at *www.epa.gov/dfe*.

Small Business Compliance Assistance Centers

The Office of Compliance, in partnership with industry, academic institutions, environmental groups, and other federal and state agencies, has established national Compliance Assistance Centers for nine specific industry sectors heavily populated with small businesses that face substantial federal regulation. These sectors are printing, metal finishing, automotive services and repair, agriculture, commercial transportation, paint and coating applications, the printed wiring board industry, municipalities and small chemical manufacturers.

The purpose of the Centers is to improve compliance of the customers they serve by increasing their awareness of the pertinent federal regulatory requirements and by providing the information that will enable them to achieve compliance. The Centers accomplish this by offering the following:

- "First-Stop Shopping" - serve as the first place that small businesses and technical assistance providers go to get comprehensive, easy to understand compliance information targeted specifically to industry sectors.

- "Improved Information Transfer" - via the Internet and other means, create linkages between the small business community and providers of technical and regulatory assistance and among the providers themselves to share tools and knowledge and prevent duplication of efforts.

- "Compliance Assistance Tools" - develop and disseminate plain-English guides, consolidated checklists, fact sheets, and other tools where needed by small businesses and their information providers.

- "Links Between Pollution Prevention and Compliance Goals" - provide easy access to information and technical assistance on technologies to help minimize waste generation and maximize environmental performance.

- "Information on Ways to Reduce the Costs of Compliance" - identify technologies and best management practices that reduce pollution while saving money.

For general information regarding EPA's compliance assistance centers, contact Tracy Back at (202) 564-7076.

VIII.C. Trade Association/Industry Sponsored Activity

VIII.C.1. Industry Research Programs

American Petroleum Institute- Strategies for Today's Environmental Partnership (STEP)

The STEP (Strategies for Today's Environmental Partnership) program was developed by API member companies to address public environmental concerns by improving the industry's environmental, health, and safety performance; documenting performance improvements; and communicating them to the public. The foundation for STEP is the API Environmental Mission and the API Guiding Environmental Principles. The program also includes a series of environmental strategic plans; a review and revision of existing industry standards; documentation of industry environmental, health, and safety performance; and mechanisms for obtaining public input. In 1992, API endorsed, as part of STEP, adoption of management practices as an API recommended practice. The management practices contain the following elements: pollution prevention, operating and process safety, community awareness, crisis readiness, product stewardship, proactive government interaction, and resource conservation. The management practices are an outline of actions to help companies incorporate environmental health and safety concerns into their planning and decision making. Each company will make its own decisions on how and whether to change its operations. API has developed a compilation of resources that provide recommendations and guidance on various operational areas of the oil industry to assist API members with their implementation of the management practices.

STEP is a program of the American Petroleum Institute (API) that strives to improve and promote the industry's commitment to environmental, health, and safety issues. The program encompasses many projects performed by member companies, plus research performed by API. STEP is involved with environmental issues on two fronts: research, and communications with both member companies and external entities.

STEP sponsors a wide range of research on environmental issues, including studies on releases, exposure assessments, and pollution prevention assessments. In many cases, the data leads toward the setting of API industry standards, which are often cited in EPA regulations.

The program also serves to disseminate information about environmental and health issues to the public. An example is the *Petroleum Industry Environmental Performance Annual Report*, which presents statistics on the progress of the industry in reducing its environmental impacts.

API's Upstream Department undertakes a range of activities focused on environmental issues facing the oil and gas extraction industry. Sponsored research may identify available, cost-effective techniques for control of emissions or remediation of a spill. Workshops are sponsored to assist companies (both members and nonmembers) in complying with new regulations or applying new technologies. As an example, API sponsored research on the remediation of soils affected by salt resulting from decades-old discharges or more recent spills of produced water. From this research has grown a series of workshops to transfer this information to companies and state agencies working to address these sites.

Gas Research Institute (GRI)

The Gas Research Institute is headquartered in Chicago and manages a cooperative research, development, and commercialization program for the mutual benefit of the natural gas industry. GRI works with research organizations, manufacturers and its member companies to develop gas technologies and to transfer new products and information to the marketplace.

GRI has published studies of waste generation and management in the natural gas industry. "Waste Minimization in the Natural Gas Industry: Regulations, Methodology, and Assessment of Alternatives" is of particular interest. The publication provides a thorough overview of waste generation in the industry and methods for minimizing many of the waste streams. (Contact: *www.gri.org/* or (773) 399-8100.)

VIII.C.2. Trade Associations

American Petroleum Institute (API) 1220 L Street, NW Washington, DC 20005 Phone: (202) 682-8000 Fax: (202) 962-4797	Members: 500 Staff: 300 Budget: $40,000,000 Contact: Mark Rubin *www.api.org/*

The American Petroleum Institute (API) is the largest trade group for the oil and gas industry, with the largest membership and budget. API represents major oil companies, and independent oil producers, refiners, marketers, and transporters of crude oil, lubricating oil, gasoline, and natural gas. API conducts and promotes research in the oil and gas industry and collects data and publishes statistical reports on oil production and refining. Numerous manuals, booklets, and other materials are published on oil and gas exploration and production.

Independent Petroleum Association of America (IPAA) 1101 16th St., NW Washington, DC 20036 Phone: (202) 857-4722 Fax: (202) 857-4799	Members: 6,000 Staff: 25 Contact: Gil Thrum www.ipaa.org/

IPAA was founded in 1929 to represent small oil and natural gas producers in legislative and regulatory issues at the federal level. Its members are principally well operators and royalty owners, plus others involved in the industry such as suppliers, and drilling contractors. IPAA collects production, consumption, and economic data on the industry and publishes documents including *The Oil and Natural Gas Producing Industry in Your State.*

Society of Petroleum Engineers (SPE) PO Box 833836 Richardson, TX 75083-3836 Phone: (214) 952-9393 Fax: (214) 952-9435	Members: 53,000 Staff: 92 Budget: $15,000,000 Regional Groups: 13 Local Groups: 137 Contact: Dan K. Adamson www.spe.org/

SPE was founded in 1922 to serve petroleum engineers involved with oil and gas exploration and production. The organization has 53,000 members and a budget of $15 million. SPE publishes several journals and books, including the monthly *Journal of Petroleum Technology*, that report on reservoir characterization and management methods and industry statistics.

Association of Oilwell Servicing Contractors (AOSC) 6060 N. Central Expy., Ste. 428 Dallas, TX 75206 Phone: (214) 692-0771 Fax: (214) 692-0162	Members: 600 Staff: 4 Budget: $500,000 Regional Groups: 16 Contact: M.L. Clark

AOSC was founded in 1956, and represents oil well servicing and workover contractors, equipment manufacturers, and others related to the well servicing industry. The organization publishes the monthly *AOSC Newsletter*, which includes industry news, rig activity information, and legislative updates, and *Well Servicing*, a bimonthly journal that includes articles on new technology, equipment and products.

Mid-Continent Oil and Gas Association (MCOGA) 801 Pennsylvania Ave NW, Ste. 840 Washington, DC 20004-2604 Phone: (202) 638-4400 Fax: (202) 638-5967	Members: 7,500 Staff: 6 State Groups: 4 Contact: Albert Modiano

The Mid-Continent Oil and Gas Association was founded in 1917 and represents oil and gas producers, royalty owners, refiners, gasoline manufacturers, transporters, drilling contractors, supply and equipment dealers and wholesalers, bankers, and other individuals interested in oil business.

Western States Petroleum Association (WSPA) 505 N. Brand Blvd., Ste. 1400 Glendale, CA 91203-1925 Phone: (818) 545-4105 Fax: (818) 545-0954	Members: 35 Staff: 32 Regional Groups: 4 Contact: Douglas Henderson *www.wspa.org/*

The Western States Petroleum Association was founded in 1907 and represents companies involved with petroleum exploration, production, refining, transportation, and wholesale marketing in Arizona, California, Hawaii, Nevada, Oregon, and Washington. WSPA offers advisory services for industry members.

Offshore Operators Committee (OOC) P.O. Box 50751 New Orleans, LA 70150 Phone: (504) 593-7443 Fax: (504) 593-7544	Members: 110 Staff: 1 Contact: Mr. Virgil Harris e-mail: *virgil_a_harris@cngp.cng.com*

OOC is an industry cooperative representing nearly all of the operators in the Gulf of Mexico. They sponsor research on the effects of oil and gas operations offshore and work with EPA on updates to offshore NPDES permits.

Petroleum Technology Transfer Council (PTTC) 1101 16th Street, NW, Suite 1-C Washington, DC 20036 Phone: (202) 785-2225 or (800)THE-PTTC Fax: (202) 785-2240	Regional Centers: 10 Contact: Deborah Rowell *www.pttc.org/*

The Petroleum Technology Transfer Council (PTTC) was formed in 1994 by the U.S. oil and natural gas exploration and production industry to identify and transfer upstream technologies to domestic producers. PTTC's technology programs help producers reduce costs, improve operating efficiency, increase ultimate recovery, enhance environmental compliance, and add new oil and gas reserves. Through its 10 regional resource centers located at universities around the country, PTTC offers expert assistance, information resources, inter-disciplinary referrals, and demonstrations of E&P software solutions.

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IX. CONTACTS/ACKNOWLEDGMENTS/RESOURCE MATERIALS

For further information on selected topics within the oil and gas extraction industry, a list of contacts and publications are provided below.

Contacts[4]

Name	Organization	Telephone	Subject
Dan Chadwick	EPA/OECA (Office of Enforcement and Compliance Assurance)	(202) 564-7054	Compliance Assurance
Steve Souders	EPA/OSWER (Office of Solid Waste and Emergency Response)	(703) 308-8431	Oil and Gas Wastes
Dan Derkics	EPA/OSWER (Office of Solid Waste and Emergency Response)	(703) 308-8409	Oil and Gas Wastes
Bruce Kobelski	EPA/OW (Office of Water)	(202) 260-7275	Underground Injection
Tom Aalto	EPA/Region VIII	(303) 312-6949	RCRA / Problem Oil Pits
Ron Jordan	EPA/OW (Office of Water)	(202) 260-7115	NPDES Issues
Greg Nizich	EPA/OAQPS (Office of Air Quality Planning and Standards)	(919) 541-3078	Air Issues
Ralph Russell	DOE/EIA (Department of Energy, Energy Information Administration)	(214) 720-6196	Industry Processes
Mike Miller	Louisiana Department of Environmental Quality	(225) 765-0272	Industry Processes, State Waste Minimization Program
Charles Koch	North Dakota Industrial Commission, Oil and Gas Division	(701) 328-8020	Industry Processes
James Erb	Pennsylvania Department of Environmental Protection	(717) 772-2199	Industry Processes
Jack Ward	Texas Railroad Commission, Oil and Gas Division	(512) 475-4580	State Waste Minimization Programs, Pollution Prevention

[4] Many of the contacts listed above have provided valuable information and comments during the development of this document. EPA appreciates this support and acknowledges that the individuals listed do not necessarily endorse all statements made within this notebook.

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